SB 21

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<TARGET><BILL>SB 21</BILL><SUBJECT>SB 21 (FILE 4)</SUBJECT><COMM>HFIN28</COMM></TARGET>

TESTIMONY OF EXXONMOBIL
ON ALASKA'S INVESTMENT CLIMATE
TO THE ALASKA HOUSE FINANCE COMMITTEE ON
APRIL 8, 2013

Mister Chairman, members of the committee:

For the record, my name is Dan Seckers. I am ExxonMobil's Tax Counsel, based in Anchorage. I want to thank the committee for the opportunity to express ExxonMobil's views on Alaska's current investment climate and the impacts of Alaska's oil and gas production tax or ACES.

Let me begin by underscoring what many of you have likely heard ExxonMobil say throughout the years - that Alaska has been and continues to be an important component of ExxonMobil's world-wide investment portfolio. We have had a presence in Alaska for over 50 years and have been a key player in Alaska's oil industry development. We are the operator of Point Thomson, hold the largest working interest at Prudhoe Bay (36.4%) and are the largest lease holder of discovered Alaska gas resources. We are committed to Alaska and its future and expect to be involved here for many years to come.

Let me also state that ExxonMobil continues to support Governor Parnell's efforts toward substantive reform of ACES. We appreciate his willingness to champion this difficult issue for the past two years and his committed effort again this legislative session. The need for Alaska to develop a competitive, stable fiscal regime that attracts the levels of investments that Alaska's North Slope requires is one of the most, if not the most, important issues facing the State. We believe the Governor's four core "principles", as emphasized in his State of the State speech that any reform of ACES:

- Be fair to Alaskans
- Encourage new oil production
- Simplify and restore balance to Alaska's fiscal system
- Make Alaska competitive for the long term

can form the foundation of a successful, long-term taxation policy for the State.

The Governor has not been alone in his efforts. Many members of the Legislature have worked hard the past two years to examine and understand the impact of ACES on Alaska's global competitiveness. That hard work has been having a positive effect as it appears legislators and most Alaskans now recognize that Alaska's production tax system is not well designed to tackle the production decline and attracting investments to develop new production.

Consistent with the testimony we have given over the past several years, ExxonMobil believes that the changes made to Alaska's oil and gas production tax since 2005 have had a negative impact on business activity in Alaska and Alaska's overall investment climate. Fundamentally, the progressivity component of the ACES tax regime, on top of an already high base tax rate, creates a major disincentive to invest in the high-risk, high-cost opportunities available in Alaska. These two features must be addressed for any tax policy to be successful in meeting the State's desired production and long-term revenue goals.

Two aspects of the current tax policy, however, are pro-development. The deduction of operating and capital expenditures before applying the tax rates recognizes the high cost of doing business in Alaska. The further tax credit for capital expenditures rewards those who invest in future production and infrastructure. These are key components of the current ACES whose benefits should be reflected in any revised tax policy the State is considering.

As the Legislature's and State's own consultants have indicated over the previous two legislative sessions and during the various hearings in both bodies this legislative session, Alaska has one of the highest and most punitive tax systems in the world. The high progressivity is directly impeding Alaska's global competiveness. To significantly grow state revenues, secure jobs and stem the production decline, it is essential that Alaska's tax structure encourages long-term development of all of Alaska's resource potential.

As the Governor has stated, Alaska's fiscal regime must be competitive and durable for the long term. ExxonMobil values a predictable fiscal environment in which to make long term investment decisions. Our investments are capital intensive and are evaluated over timeframes of decades. Any change in the fiscal regime has a direct impact on how we view stability of the Alaskan fiscal environment, which in turn impacts how we evaluate the risk basis of future investment decisions. Because of the nature and magnitude of the risks associated with any oil or gas investment, coupled with the long lead time required to recoup that investment, stable fiscal terms are key to any investment decision.

To date, Alaska has produced more than 16 billion barrels of oil from the North Slope, and according to the Department of Natural Resources there are over 5 billion barrels of known resources remaining. These undeveloped resources represent a substantial opportunity, but their development is at risk under the current ACES tax system. Oil production today is less than one-third of the peak oil production of more than 2 million barrels per day in 1988, and annual production continues to decline.

You have heard about the continued and alarming decline of North Slope oil production from the Department of Revenue, State consultants and individuals that have testified earlier. But it is important to reemphasize that industry currently invests more than $1 billion per year just to maintain current North Slope oil production decline at six to seven percent. The substantial majority of that annual investment is in the legacy fields – Prudhoe Bay and Kuparuk. Absent that continued investment, the annual production decline would likely be in the range of 12 to 15 percent annually. Without meaningful tax reform that includes Alaska's legacy fields, Alaska can expect production declines to continue.

Production from the legacy fields not only provides the majority of the State's revenues, it sustains the current North Slope infrastructure and the operation of TAPS, which are critical to enabling new production. The infrastructure from these legacy fields has been leveraged historically for satellite developments, such as Pt. McIntrye, Orion, Borealis and other non-legacy fields to economically process and transport their oil from the North Slope to refinery destinations. If the large legacy fields did not exist, it is unlikely any of these other developments would have been economic.

Without healthy legacy fields, the prospects of any future new fields or developments become even more economically challenged and the probabilities of Alaska reaching its desired goal of long-term sustained production levels more difficult.

Encouraging increasing investment to keep these key fields healthy is therefore at least as important as encouraging investment in exploration and development of new fields. For any tax reform to contribute to the Governor's stated objectives for Alaska's long-term production, it must also be applicable to the legacy fields where the State's near and long term economic future rests.

Considerable attention has been placed on making Alaska more competitive relative to other regimes. While that focus is extremely important, it is only part of the overall picture. Benchmarking government take against other producing areas is a useful tool for gauging basic competitiveness, but does not provide the full picture of investment health. As the Department of Revenue and various consultants have testified, spending on the North Slope has remained relatively flat since the enactment of ACES. But what needs to be clarified is that the majority of that spending has been for maintenance and upkeep to sustain existing operations, not for new development. Under ACES, the State has not attracted the new investment needed to increase production.

Complicating Alaska's production decline is its high exploration, development and production costs. Alaska is one of the most expensive places in the world to develop and produce oil and gas. Many factors contribute to Alaska's higher costs including:

- Severe arctic conditions, placing limitations on when drilling and other operations can be undertaken
- Environmental challenges
- Remote location of the resource and distance to market
- Restriction of exploration opportunities

These are complications that Alaska faces that most other areas do not; but they do factor into the economic decisions being taken by investors and need to be considered when assessing what is Alaska's optimum production tax regime.

ExxonMobil is willing to accept the risks of long-term, capital intensive investments when a stable tax structure allows and encourages investment and ensures a corresponding opportunity for upside potential. Upside factors such as increased production and higher prices can compensate for risks taken by investors, because companies are certainly negatively impacted when lower than expected production or prices occur. The high marginal tax rates under the progressive structure of ACES take away the upside potential and reduce the attractiveness of those capital intensive investments, compared to other locations where the upside benefit can be retained.

Alaska faces significant challenges. As I mentioned, costs are high and production continues to decline. We all need to work together to achieve the right balance – as Governor Parnell stated - a balance that maximizes the benefit to Alaskans while encouraging industry to continue to invest in Alaska.

ExxonMobil recognizes the difficulty you face as policy makers in tackling the State's tax policy while protecting current revenue streams and addressing the revenue problems just over the horizon due to the production decline. We appreciate how hard and difficult that task is.

Today's production rates are the product of government policies, technical work, and investment decisions that in many cases were made decades ago. Increasing production rates in the decades to come will result from sound policies, decisions, and commitments that are made by this Legislature. As policy makers, you will need to decide whether Alaska's current high production tax regime is the right course for Alaska or if another course is necessary to harness the remaining resource potential, given the high costs and steadily declining oil production rates we as Alaskans face.

It is important to recognize that any decision made by this Legislature impacts much more than tax revenue in the near term and in the future. Decisions made today will influence the life of production in existing fields and investments required to develop Alaska's remaining resource potential. This will in turn impact jobs for Alaskan workers, revenue for many Alaska businesses, infrastructure that benefits Alaskan communities, and set the stage for the future of Alaska for many generations to come.

As I indicated, ExxonMobil fully supports the Governor's and this Legislature's efforts to reform ACES and to make Alaska's investment climate globally competitive. To maximize its resource potential while receiving a fair share of the resource revenues, Alaska needs a long-term resource development policy that will encourage increasing investment. The reform of ACES needs to result in a competitive, stable and predictable fiscal environment that will encourage investment at all price levels and incentivize the development of remaining resources that are economically challenged, including both new fields and resource development opportunities in existing fields. ExxonMobil believes the key focus of the reform needs to create a balanced program using a combination of changes to progressivity, the base tax rate and capital expenditure tax credits to provide a competitive balance of government take across all price bans.

Let me conclude by reiterating that ExxonMobil is committed to Alaska and to pursuing competitive investment opportunities here in the future. Unfortunately, the resource and cost structure in Alaska is becoming increasingly challenging. It is ExxonMobil's firm belief that passage of meaningful changes to ACES this year will support additional investments in Alaska that will lead to greater development and production as well as economic opportunities for Alaskans.

ExxonMobil looks forward to working with the Administration, the Legislature, industry and the people of Alaska in the pursuit and development of Alaska's oil and gas resources.

Thank you again Mister Chairman for the opportunity to testify today.

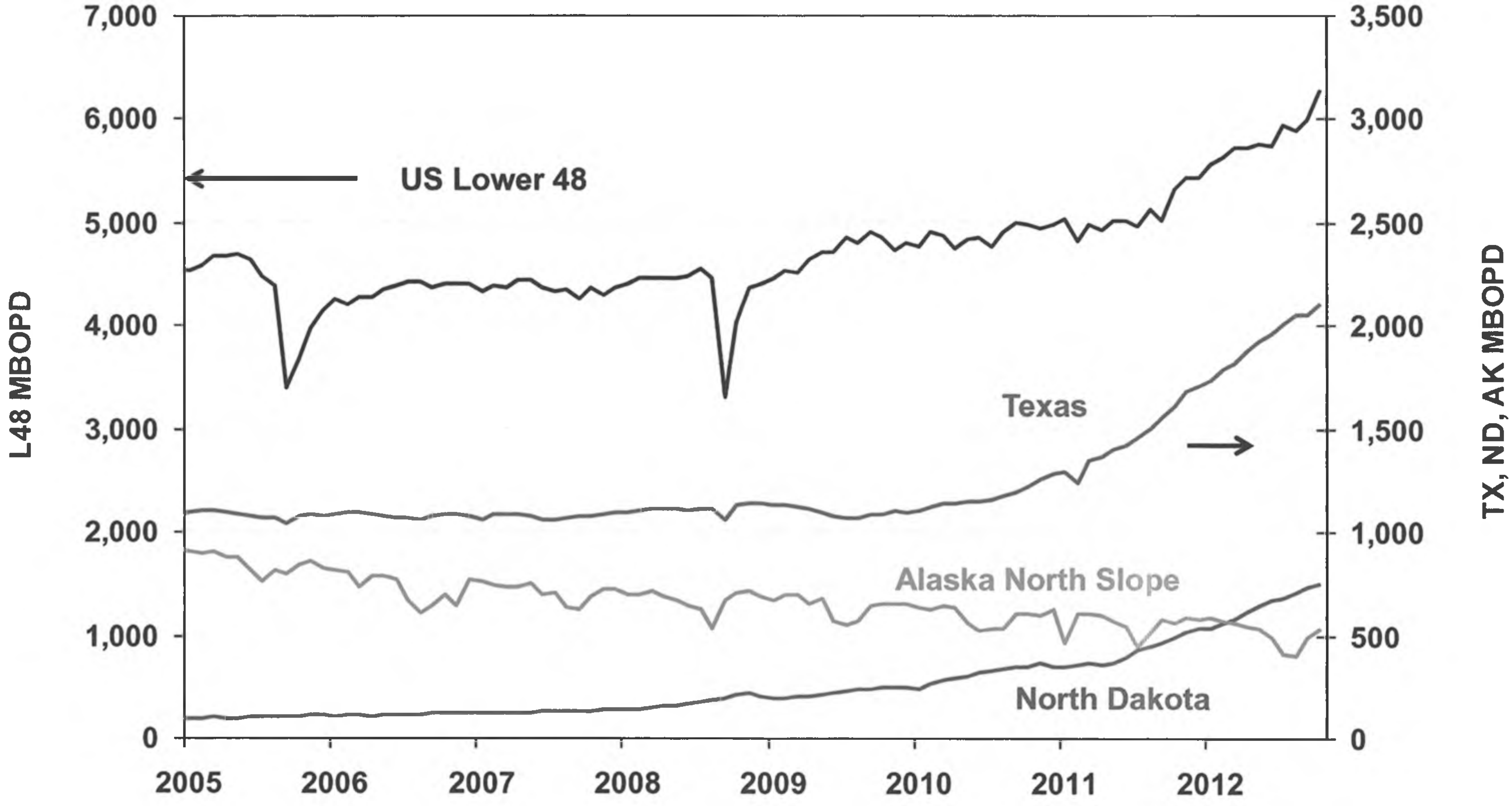
House Finance Committee

HCS SB21

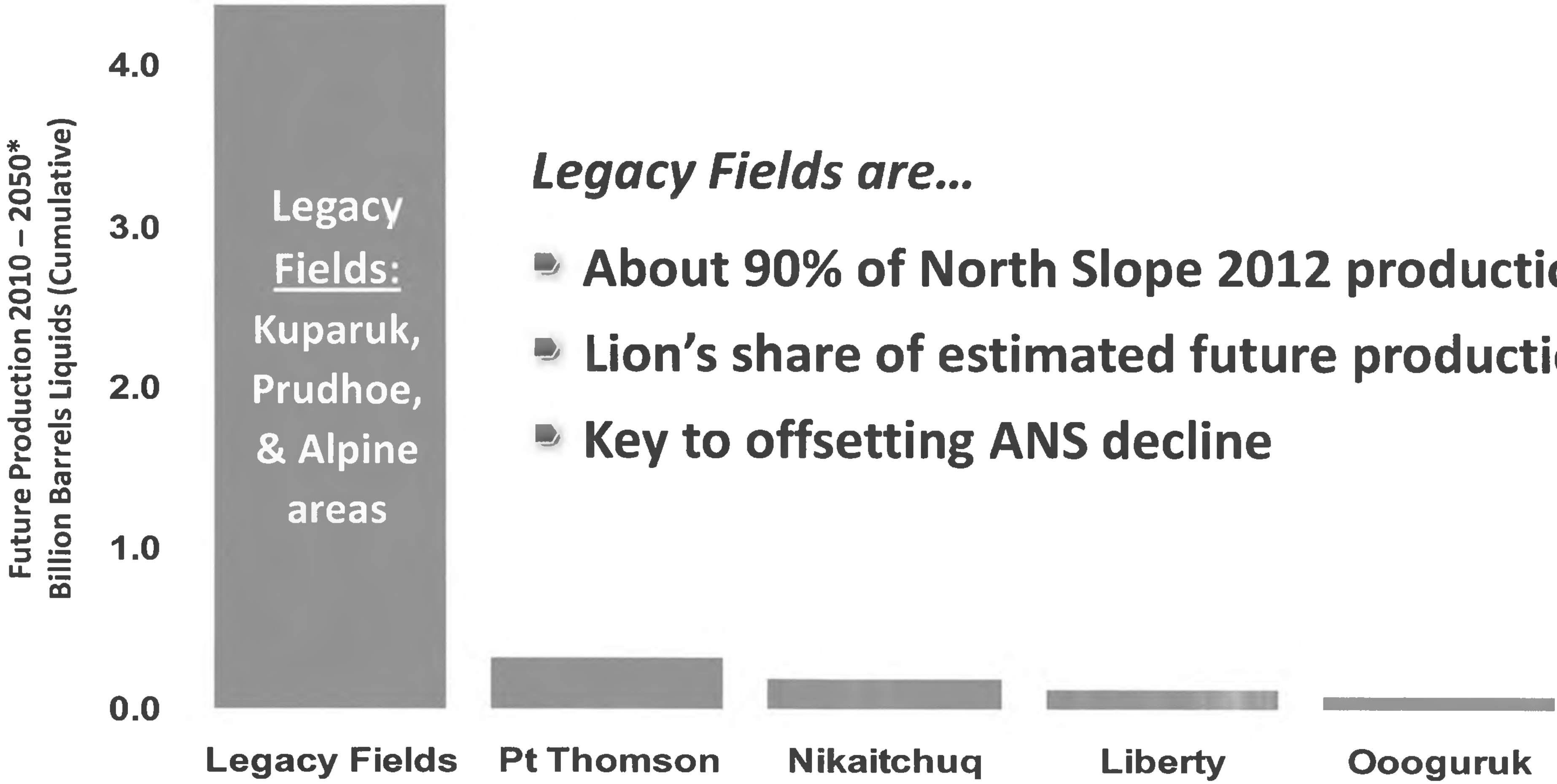
Bob Heinrich, VP Finance
Scott Jepsen, VP External Affairs
ConocoPhillips Alaska

April 8, 2013

Alaska Decline Continues While Lower 48 Continues to Increase



Alaska Legacy Fields Still Provide Significant Opportunity



Legacy Fields are...

- About 90% of North Slope 2012 production
- Lion's share of estimated future production
- Key to offsetting ANS decline

Greatest investment opportunity resides in existing legacy fields

*Source: DOR 2009 production forecast 2010 – 2050 volumes

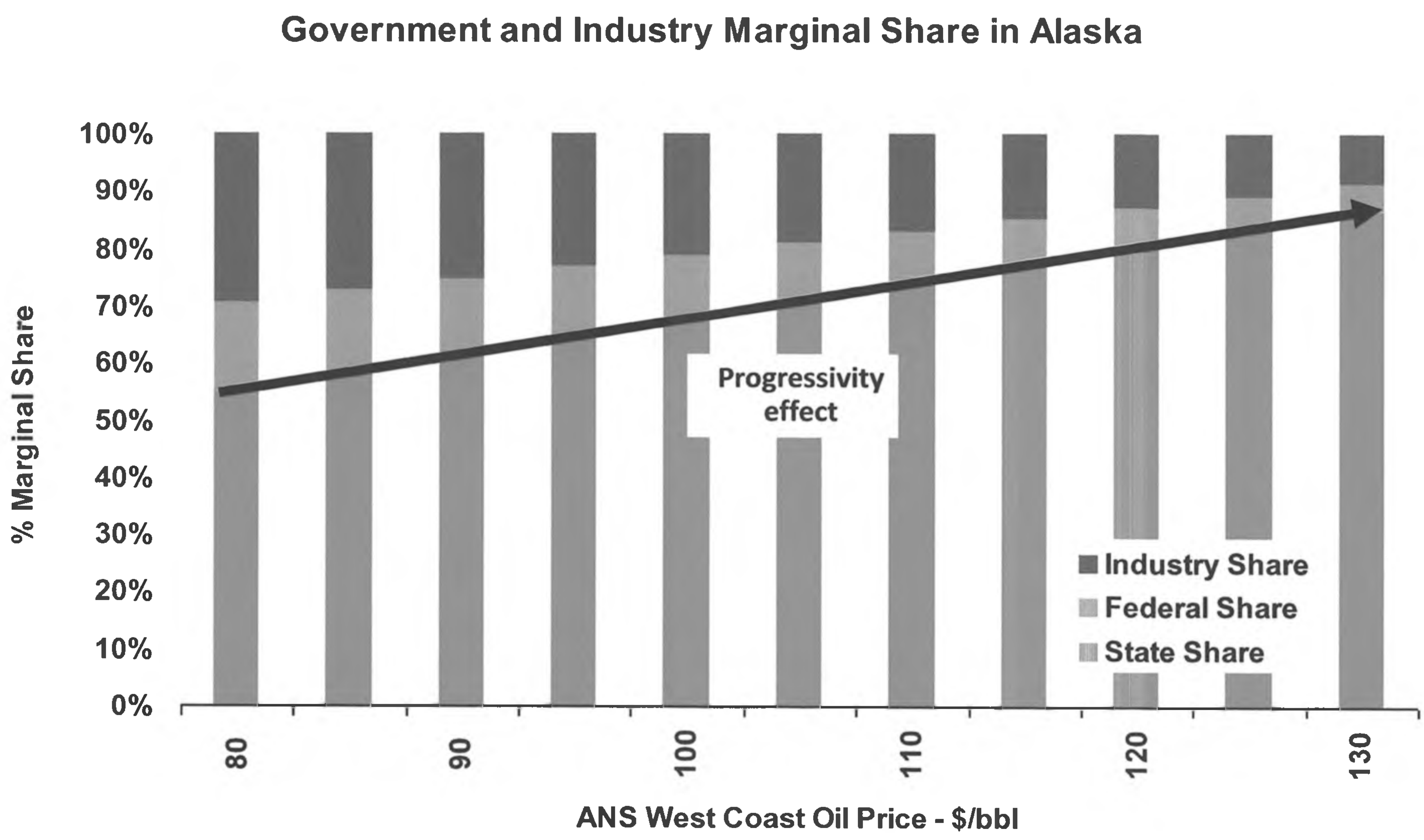
"Easy Oil" In the Legacy Fields Is Gone

- Challenged oil remains
  - Complex, high cost wells
  - Smaller reserve targets
  - Isolated fault blocks, flank oil
  - Satellites and viscous oil
  - Most new wells produce oil AND water
  - Facilities handling ~ three times as much water as oil
- **A billion dollars does not go as far as it used to...**
  - 2000 Alpine development: ~80,000 BOPD
  - 2012 CD-5 Drillsite: ~18,000 BOPD

Initial Alpine Development

CD-5 Type Development

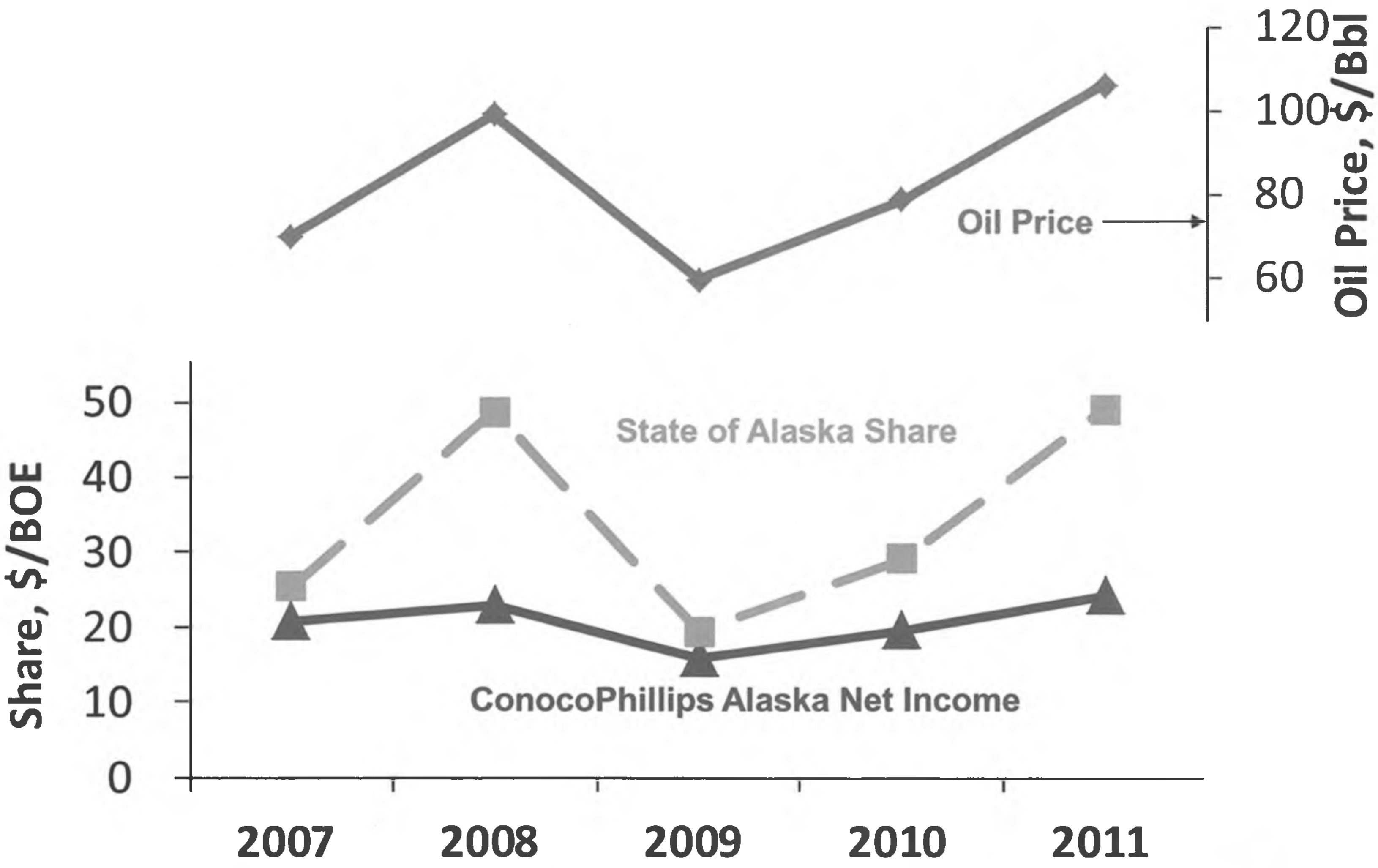
ACES Marginal Industry Share



Based on Fall 2012 Revenue Sources Book data for FY2014

ConocoPhillips

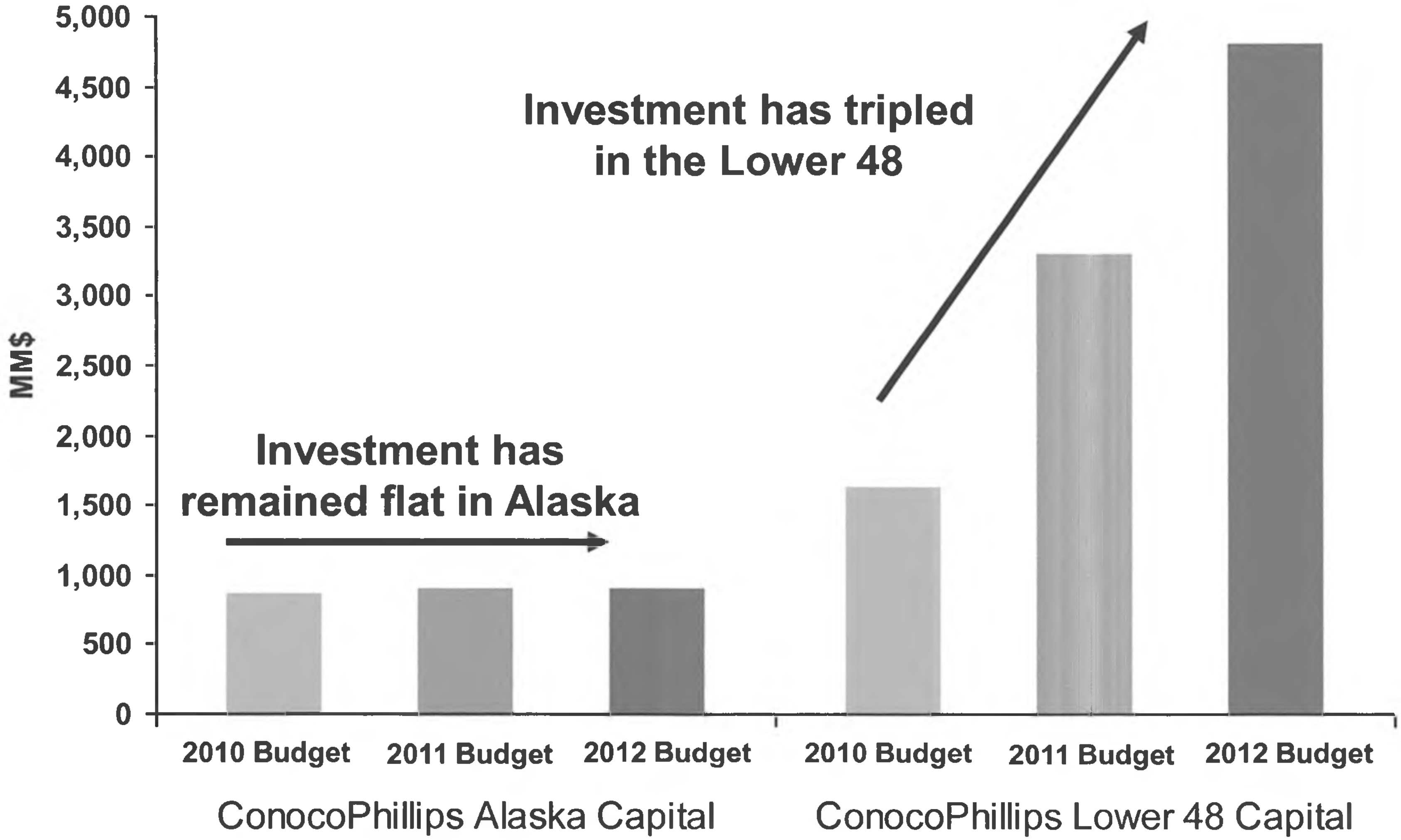
Earnings Per Barrel – ConocoPhillips Alaska and State of Alaska



ACES progressivity takes the upside

Source: ConocoPhillips 10-K, 2007-2011; State share is royalties (estimated), production tax, ad valorem tax and state income tax, oil prices are average realized prices by ConocoPhillips on the West Coast

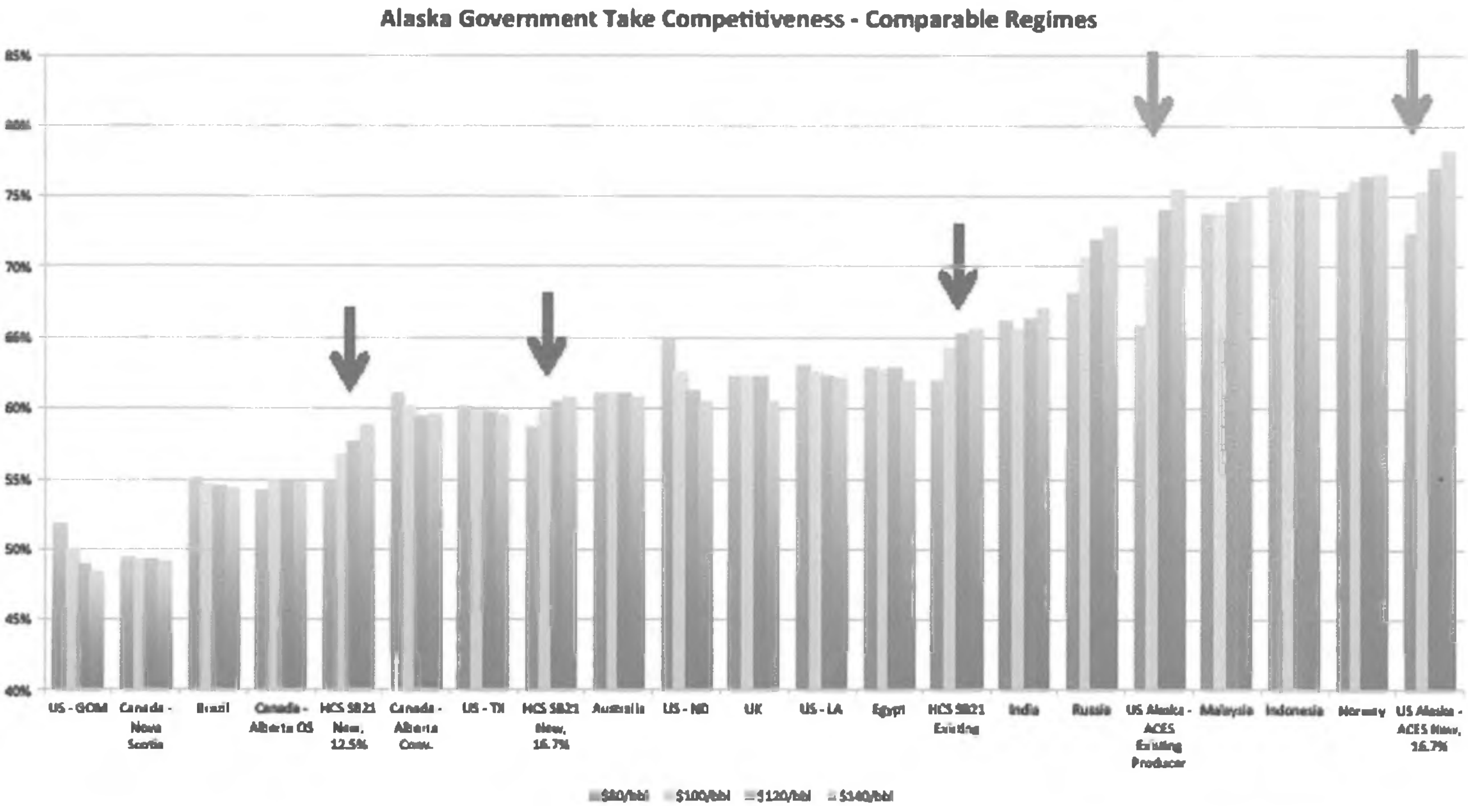
ConocoPhillips Capital Allocation



Investment flows where investor has upside

Source: ConocoPhillips 10K

Government Take Competitiveness



PFC Energy

Slide 8

Changes to ACES to Improve Alaska's Investment Climate

Objectives	HCS SB21
• Eliminate progressivity	• Slightly progressive tax structure, but significant improvement over ACES
• Create a flatter tax rate over a broad range of prices ➢ Producer and State share proportionately as prices fluctuate and margins change	• Addresses tax increase at lower prices relative to ACES (previous CS) • Hard minimum tax provides more revenue to Alaska at low prices
• Establish a tax structure creating an attractive investment climate ➢ Competitive tax rate ➢ Provide the incentives to balance Alaska's high cost environment ➢ Incentives for both legacy and new field investments	• 33% base rate is improvement • Has increased likelihood that PA expansions will receive the GVR
Question – Will proposed changes in ACES lead to increased investment?	New CS creates an environment that we believe will lead to increased investment and additional production.

BP Testimony to House Finance on HCS CSSB21 (RES)

Damian Bilbao

Head of Finance

April 8, 2013

Overview

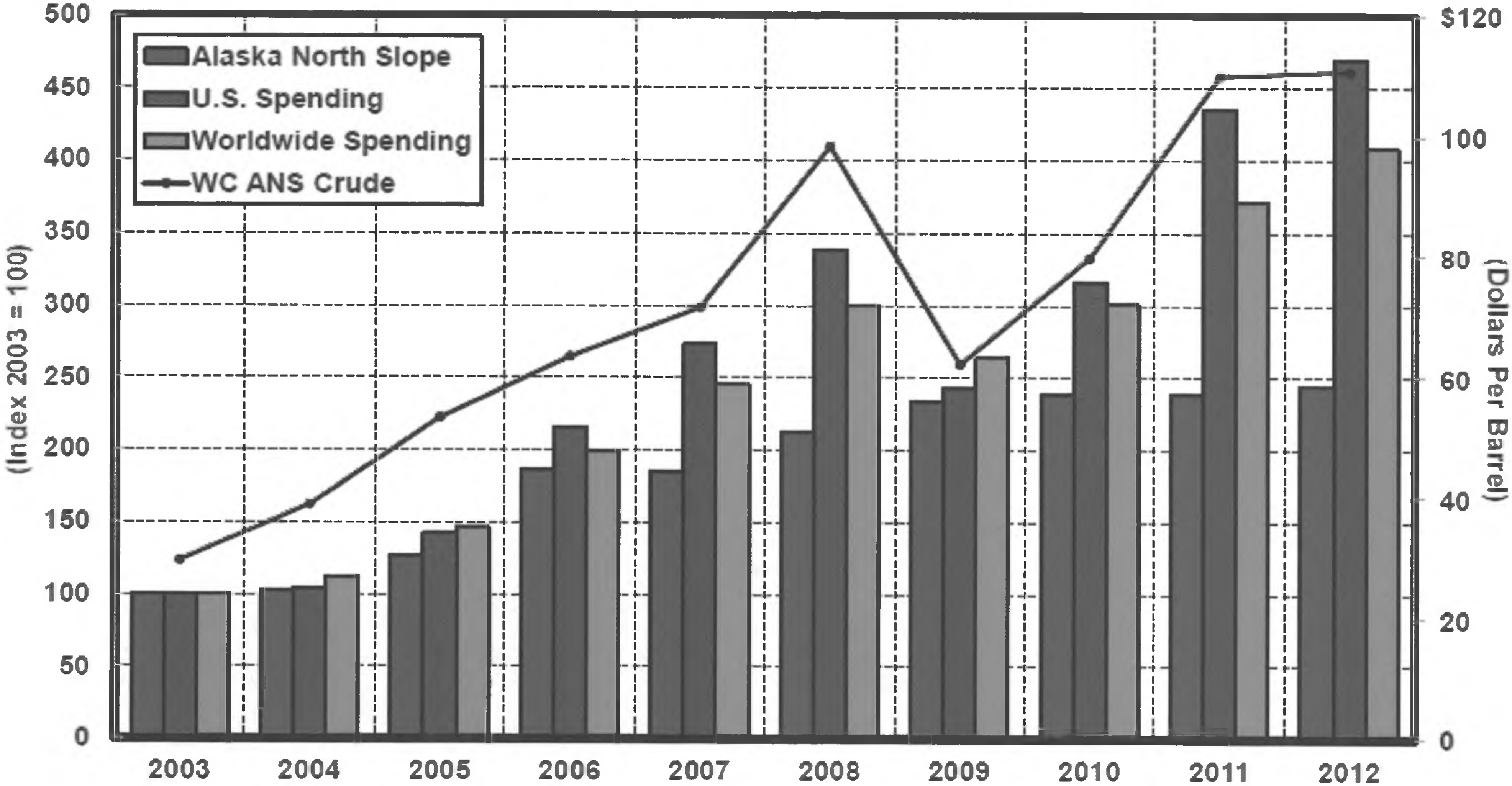
- BP in Alaska – working with the State over 50 years
- Alaska has great resource potential and people
- Under ACES, Alaska is at the back of the line in competition for investment
- HCS CSSB 21(RES) meets the Governor's four principles and will put Alaska back in the game of oil investments

BP in Alaska – 54 years, and counting...

BP presence in Alaska since 1959

- **Operating area**
  - 250 miles north of the Arctic Circle
  - 1200 sq. miles (approximately the size of Rhode Island)
  - Prudhoe Bay Unit, Endicott, Milne Point, Northstar
- **People**
  - 2,300 BP Alaska employees
  - 6,000 contract employees
- **Facilities (start-up 1977)**
  - 11 major production facilities
  - 2 major gas facilities
  - 3 water handling facilities
  - 2000 production/injection wells
- **Prudhoe Bay**
  - Original production estimate ~9.6 billion barrels
  - Cumulative production has exceeded 12 billion barrels
  - More than 2 billion barrels remaining
  - Largest field in North America – 35 years
  - COP ~36%, XOM ~36%, **BP ~26%,** CVX ~2%

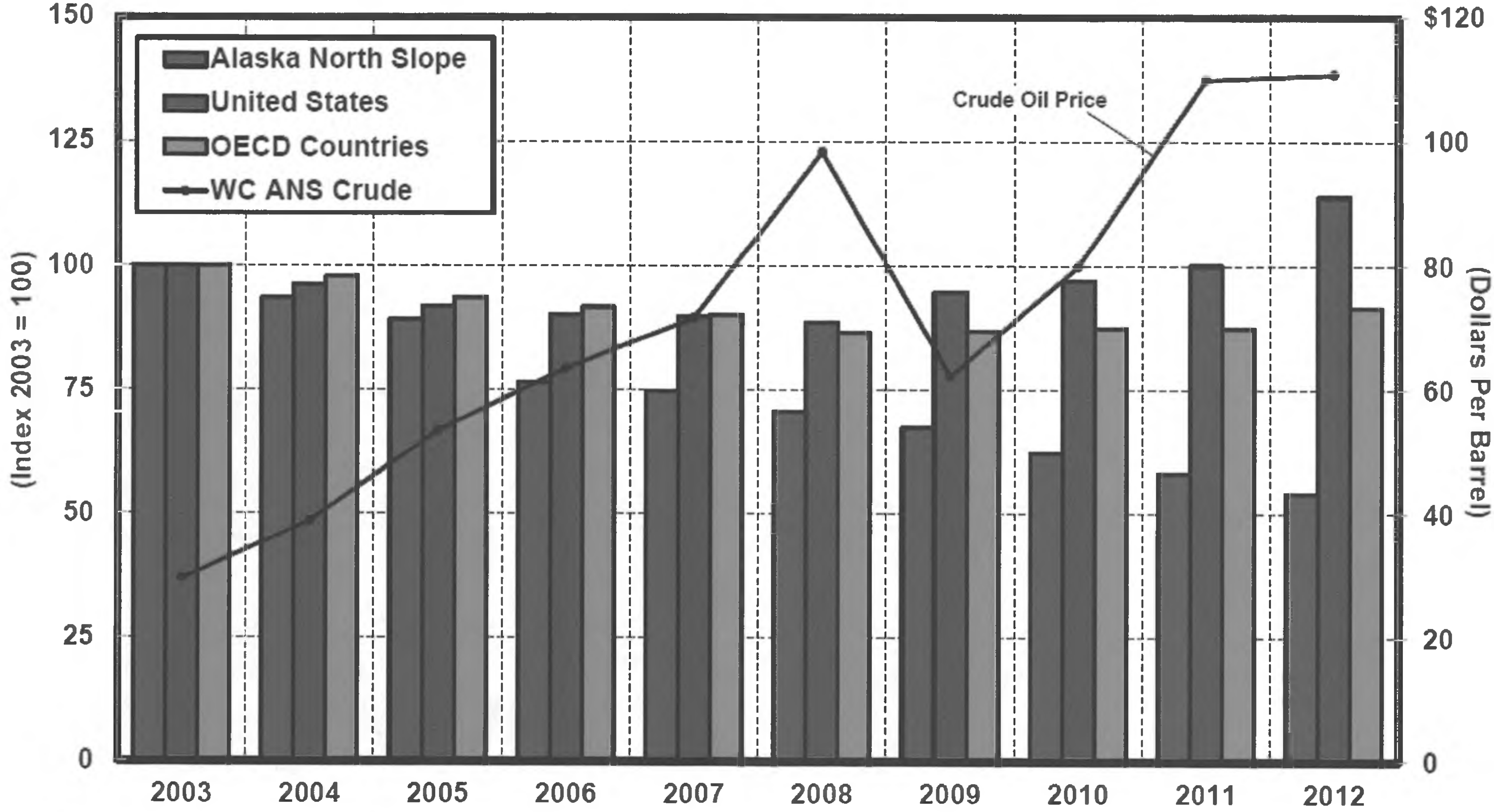
Estimated Capital Spending for Exploration and Development
Alaska North Slope vs. U.S. and Worldwide Spending*
2003 - 2012



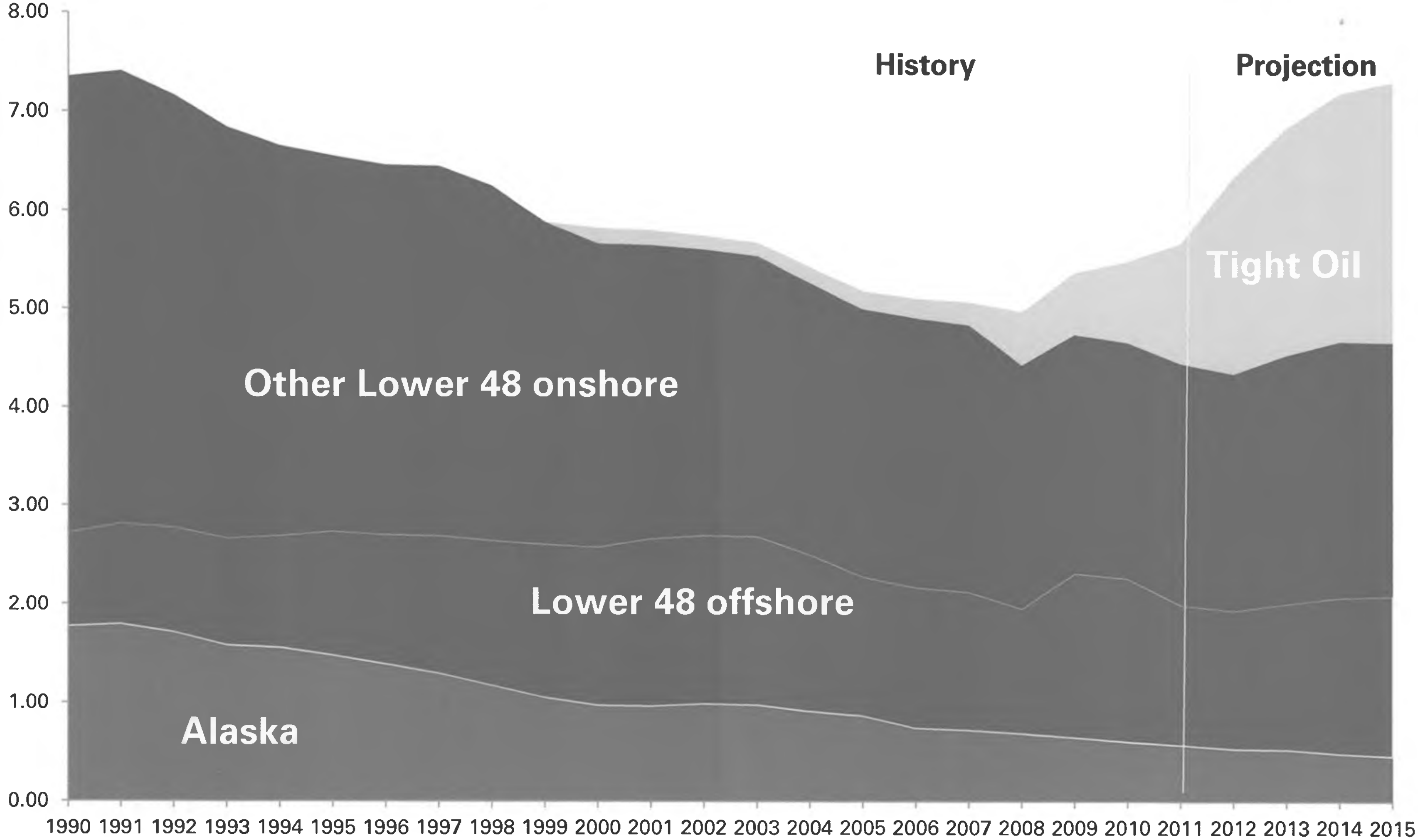
* North Slope based on tax return information; U.S. based on top 50 public companies; worldwide based on top 75 public companies

Econ One Research

Crude Oil Production
Alaska North Slope vs. United States and OECD Countries
2003 - 2012

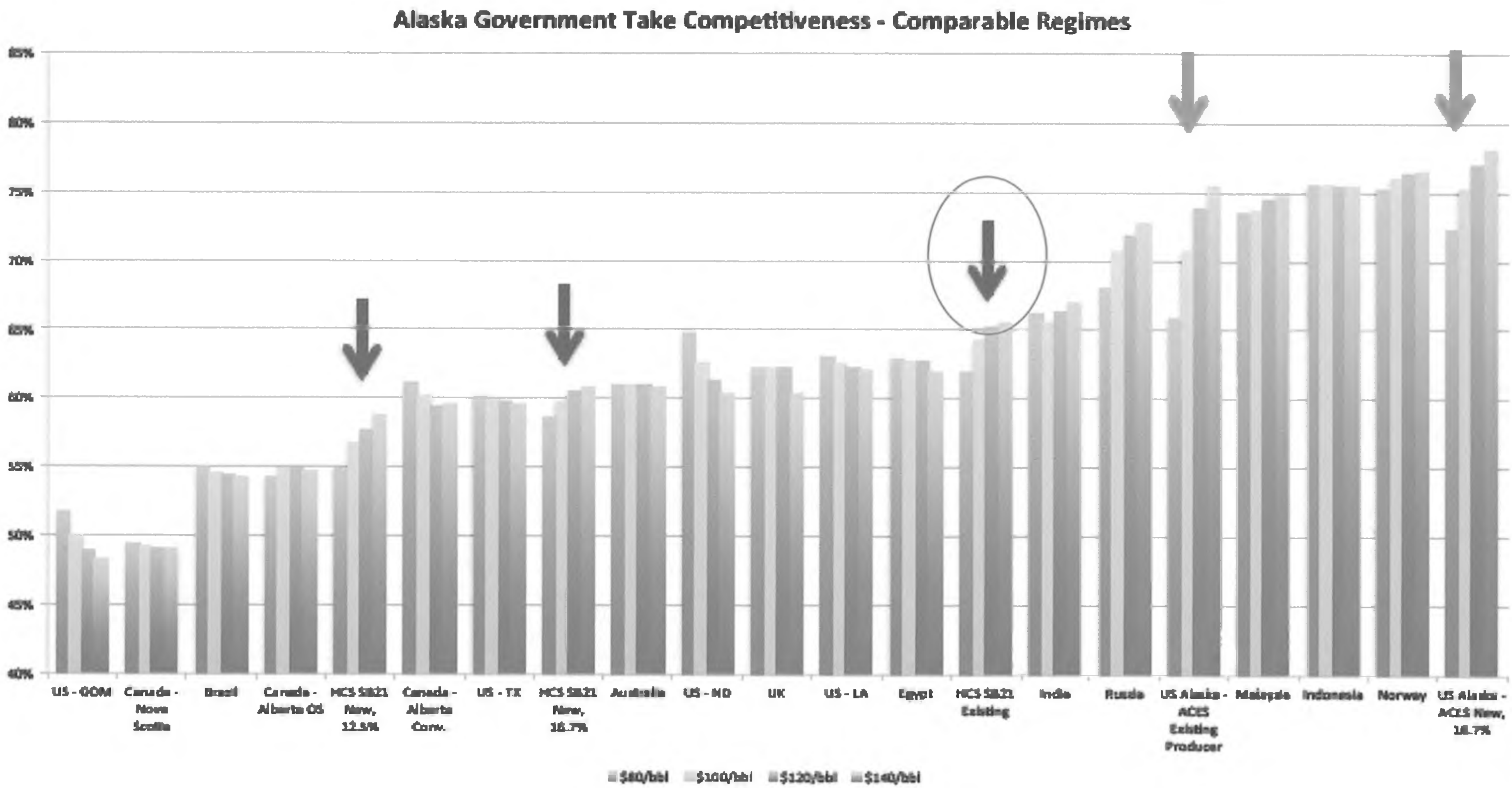


Both conventional and unconventional oil production has grown in the Lower 48



Source: EIA – Annual Energy Outlook 2013 Early Release, December 5, 2012

Alaska does not compete for investment



PFC Energy

Why doesn't ACES work?

bp

Example at $110 per barrel

Alaska State Revenue $36

Federal Income Tax $12

Deductible Costs $40

$22 – less *non-deductible expenses

AK Cost of Supply Is >$88 / bbl

*** Source: DOR RSB Fall Forecast 2012, for FY 2013***

* *AS 43.55.165(e)*

HCS CSSB 21(RES) versus ACES

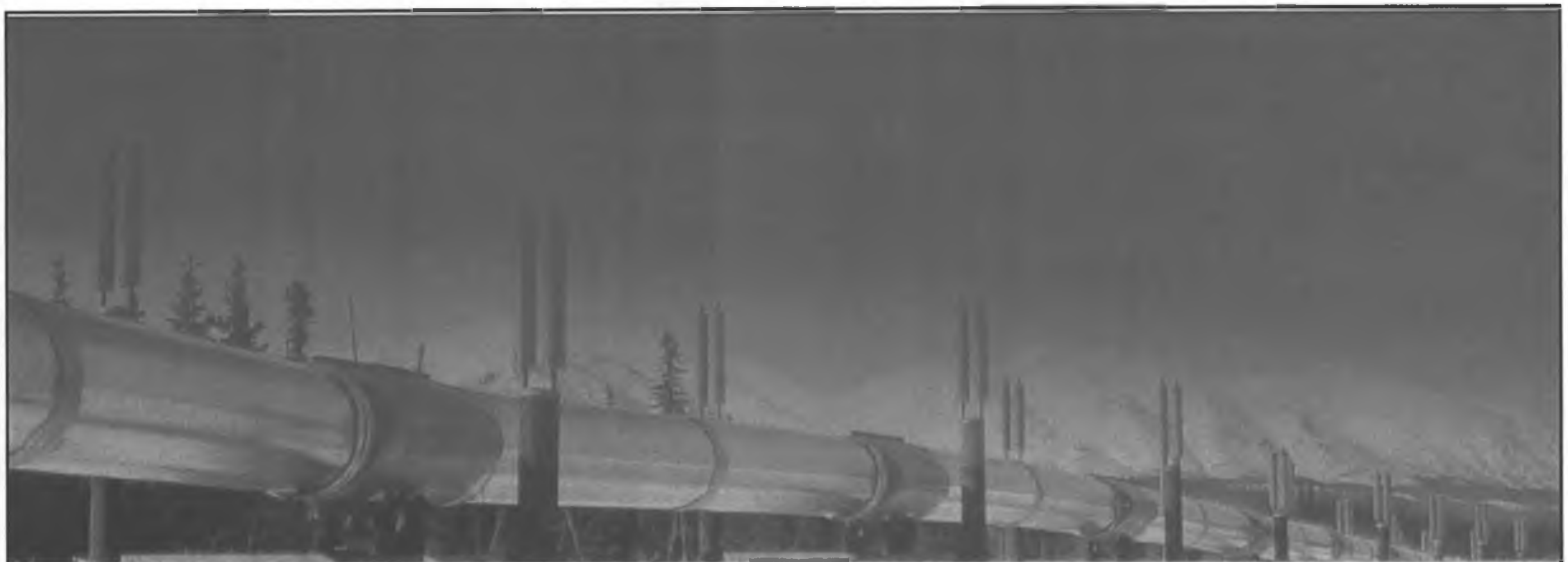
bp

ACES	HCS CSSB21(RES)
Progressivity discourages investors	Eliminates progressivity
Links credits to spend	Links credits to production
Complex	Simpler
High base rate	Higher base rate balanced with credits

In summary

- TAPS is ¾ empty and ACES has not delivered increased production
- HCS CSSB 21(RES) is a game changer and a signal that Alaska is ready to compete for investment
- The HCS CSSB 21(RES) structure could work:
  - Balances a high base rate with appropriate credits
  - Requires production to earn credits
  - Doesn't pick winners and losers
  - Provides a foundation for future opportunities

Morning



AOGA

OIL & GAS:
FUELING
ALASKA'S
ECONOMY

House Resources Committee

HCS CSSB21 (RES)

April 9, 2013

Kara Moriarty, Executive Director

AOGA Member Companies

PIONEER
NATURAL RESOURCES ALASKA

Statoil

XTO ENERGY

REPSOL

Apache

Hilcorp Alaska, LLC

ExxonMobil

bp

Alyeska pipeline
SERVICE COMPANY

TESORO

PETRO STAR INC.
EXCELLENCE IN ENERGY

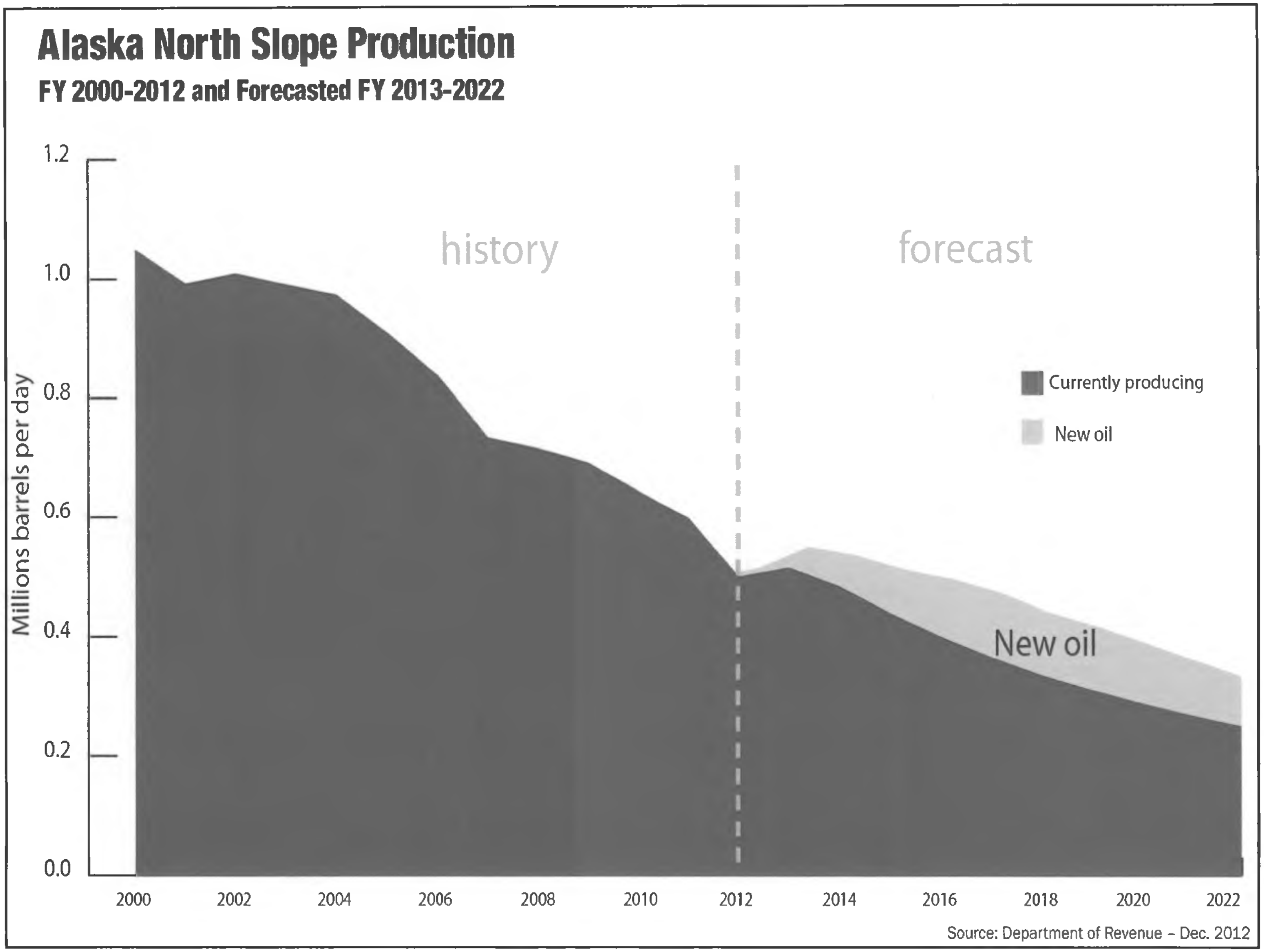
eni

petroleum

Chevron

FLINT HILL
RESOURCES®
Alaska

AOGA | Work Together. WIN Together.


Alaska North Slope Production
FY 2000-2012 and Forecasted FY 2013-2022
1.2
1.0
0.8
0.6
0.4
0.2
0.0
Millions barrels per day
history
forecast
Currently producing
New oil
New oil
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
Source: Department of Revenue - Dec. 2012

HCS CSSB21 (RES) Component: Progressivity

- *AOGA supports the elimination of ACES progressivity*

1) Progressivity under ACES takes away too large a share.

2) Progressivity guts the upside potential for Alaska investments.

3) Progressivity makes it difficult to analyze and quantify the tax effect.

AOGA | Work Together. WIN Together.

HCS CSSB21 (RES) Component: Increasing the Base Tax Rate

- *AOGA does not endorse increasing the base tax rate to 35%*

1) A higher tax rate would be a step in the wrong direction.
2) Increasing the base tax rate is contrary to the Governor's second principle. It would not encourage new production.
3) The lower the tax rate, the more attractive Alaska's system will be to investors.

AOGA | Work Together. WIN Together.

HCS CSSB21 (RES) Component: Tax Credits

1) AOGA does not support the repeal of Qualified Capital Expenditure Credits (QCE) if it was the only change, but CS offers other incentives that tend to offset this loss.

2) AOGA supports the new credits for new production.

- Gross Revenue Reduction for "non-legacy" fields
- Sliding Scale for legacy fields

AOGA | Work Together. WIN Together.

HCS CSSB21 (RES) Component: Tax Credits

3) AOGA supports the extension of the small producer tax credit.

4) AOGA supports maintaining the ability to utilize the loss carry-forward annual loss credit

AOGA | Work Together. WIN Together.

HCS CSSB21 (RES) Components: Statutory Interest & Joint Interest Billings

AOGA supports change in statutory interest

- Lowers risk/makes Alaska more competitive

AOGA supports the use of Joint Interest Billings as a starting point

- Using Joint Interest Billings as the initial source for lease expenditures is more efficient and provides consistency of what are expenses are allowable for deduction.

AOGA | Work Together. WIN Together.

HCS CSSB21 (RES)

Current bill is a significant improvement over ACES.

- Repeals high ACES progressivity
- Maintains key credit provisions while creating incentives for new production from legacy & non-legacy fields
- Reforms interest rate for tax underpayments
- Restores ability to administer the tax more effectively

Principal Downside: Higher Base Tax Rate

AOGA | Work Together. WIN Together.

4/9/13 morning

House Finance Committee

Testimony re: HCS CSSB 21(RES)

April 9, 2013

J. Patrick Foley

Land and External Affairs Manager

Incoming President, Pioneer Natural Resources, Alaska

NYSE: PXD

www.pxd.com

Pioneer Natural Resources, Alaska

Forward Looking Statements

PIONEER
NATURAL RESOURCES

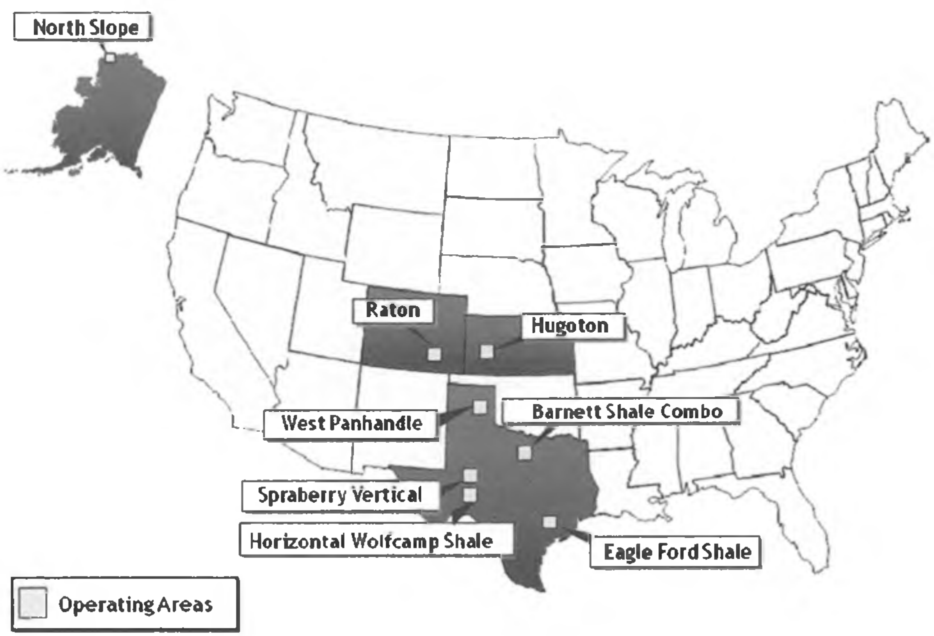
Except for historical information contained herein, the statements, charts and graphs in this presentation are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties include, among other things, volatility of commodity prices, product supply and demand, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, international operations and associated international political and economic instability, litigation, the costs and results of drilling and operations, availability of equipment, services and personnel required to complete the Company's operating activities, access to and availability of transportation, processing and refining facilities, Pioneer's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to Pioneer's credit facility and derivative contracts and the purchasers of Pioneer's oil, NGL and gas production, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the assumptions underlying production forecasts, quality of technical data, environmental and weather risks, including the possible impacts of climate change, and acts of war or terrorism. These and other risks are described in Pioneer's 10-K and 10-Q Reports and other filings with the Securities and Exchange Commission. In addition, Pioneer may be subject to currently unforeseen risks that may have a materially adverse impact on it. Pioneer undertakes no duty to publicly update these statements except as required by law.

Pioneer Natural Resources

PIONEER
NATURAL RESOURCES

Corporate overview:

- $19 Billion enterprise value
- Member of the S&P 500
- Investment grade rating
- ~3,500 employees
- $3 Billion capital budget
- $2 Billion cash flow from operations
- Leading performer in peer group



Alaska Operations Overview:

- 1st independent operator on North Slope
- 70+ full-time Alaska employees
- $14+ million in annual wages (employees)
- 150 - 300 Alaska contract workers
- ~$180 million 2013 capital budget
- ~6,000 BOPD gross production
- Net investor in Alaska

Pioneer Alaska Profile: Oooguruk

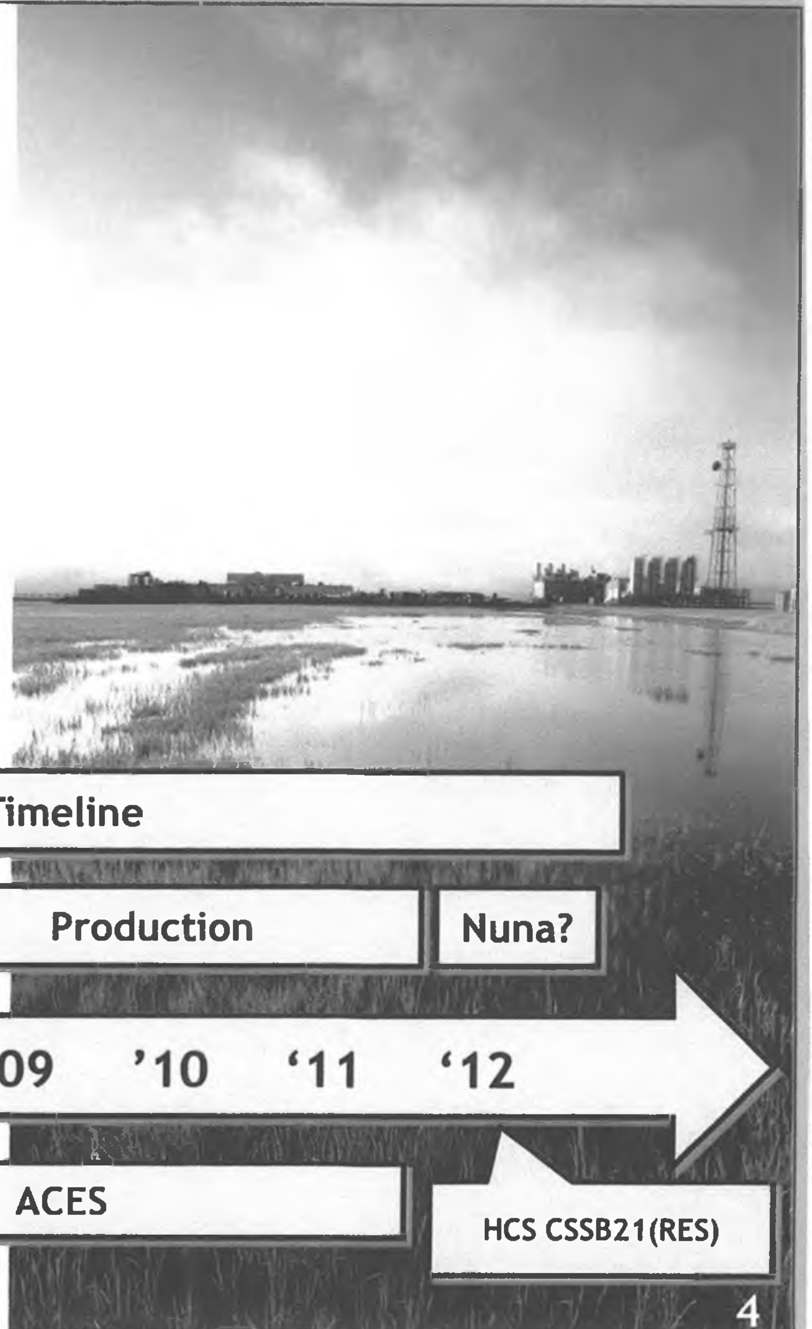
PIONEER
NATURAL RESOURCES

Exploration:

- 11 exploration wells '02 -'05
- 1 commercial project

Oooguruk Quick Facts:

- 70% Pioneer (operator) : 30% Eni
- ~$1 billion capital invested
- **12+ million barrels produced**
- ~$270 million in credits received
  (~7 % of total credits issued by the state)



Oooguruk Project and Fiscal Policy Timeline

Exploration	Sanction	Const.	Production	Nuna?

'02 '03 '04 '05 '06 '07 '08 '09 '10 '11 '12

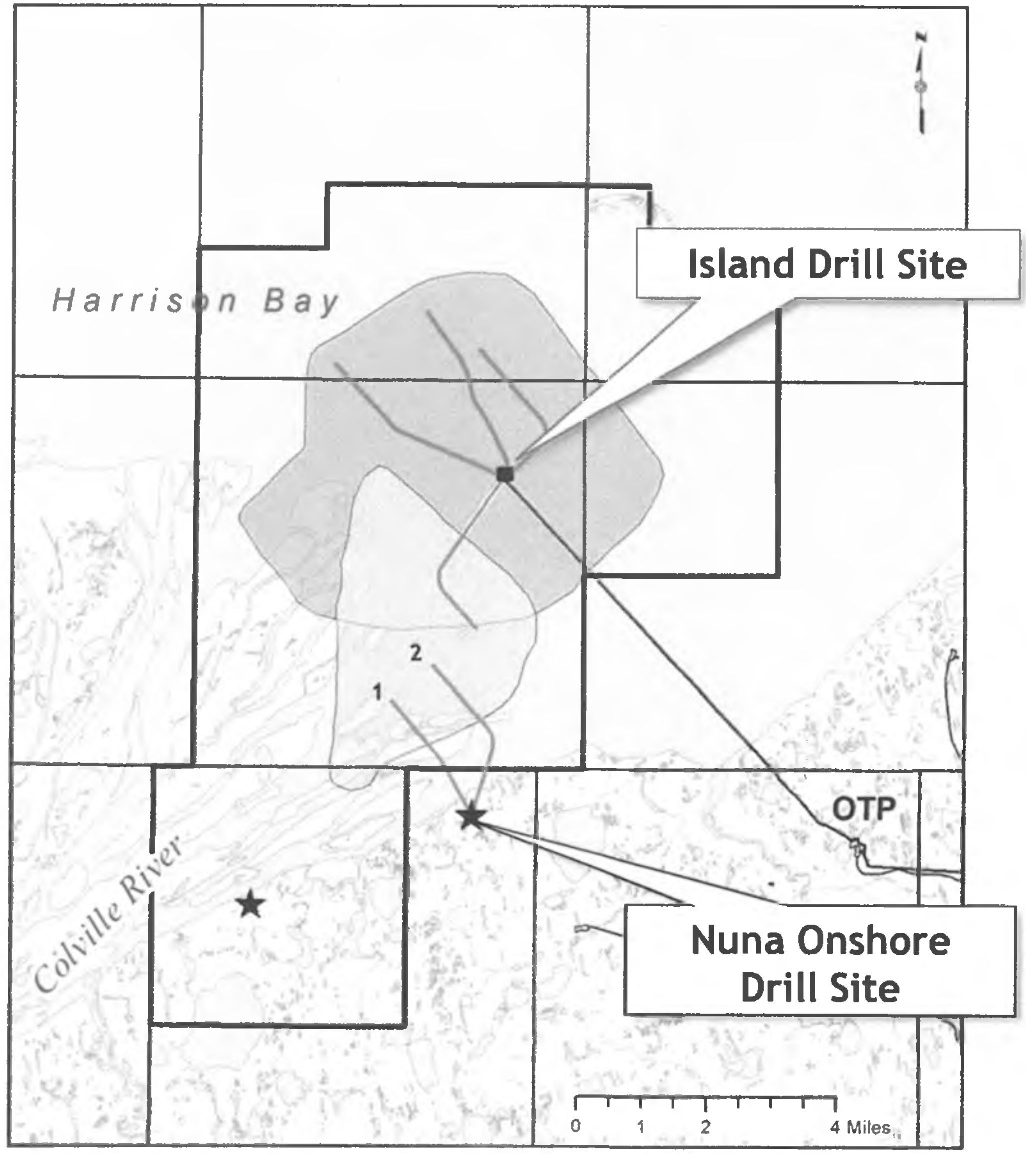
The ELF	PPT	ACES	HCS CSSB21(RES)

What's Next?

PIONEER
NATURAL RESOURCES

Nuna Project:

- $100 Million appraisal program
- ~50 MMBO of resource potential
- Phase I development overview
  - Q3 2013 sanction decision
  - ~$1 Billion capital required
  - 2015 first oil
  - 14 MBOPD peak production
  - Jobs and economic impact
- Potential for 2nd drill site
- **Must compete for limited capital against low-risk, fast-cycle projects in Lower 48**



Pioneer Competitive Resource Opportunities

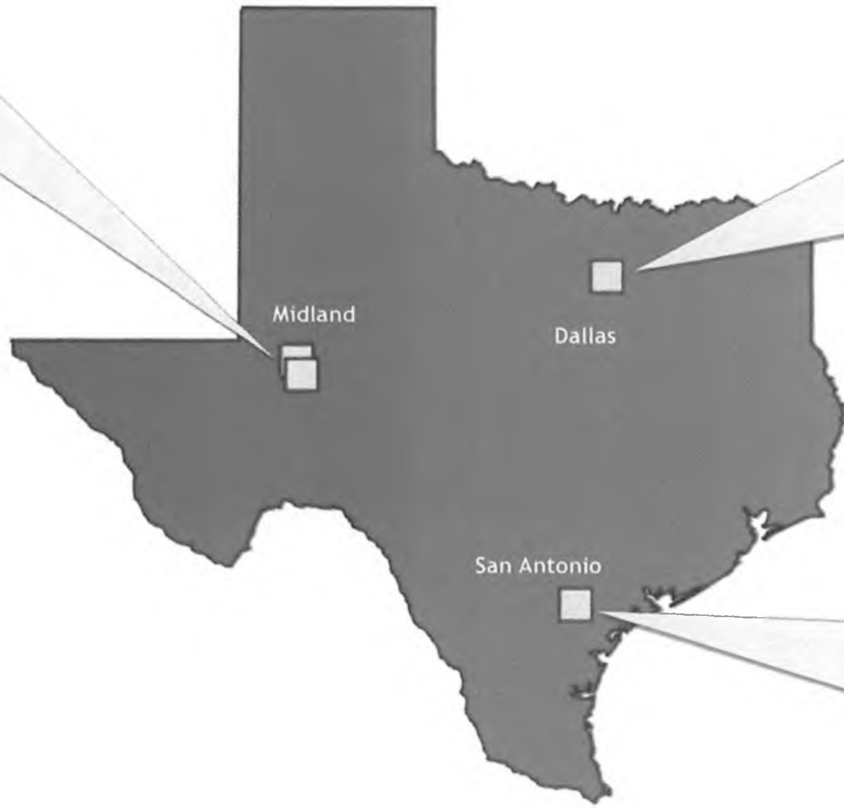
PIONEER
NATURAL RESOURCES

WOLFCAMP / SPRABERRY
$1,650 MM Drilling Program
627 MMBOE Proven

2013 Production (Growth):
75-80 MBOEPD (+14 - 21%)

Barnett Shale Combo
$185 MM Drilling Program
33 MMBOE Proved

2013 Production (Growth):
9-12 MBOEPD (+22 - 41%)



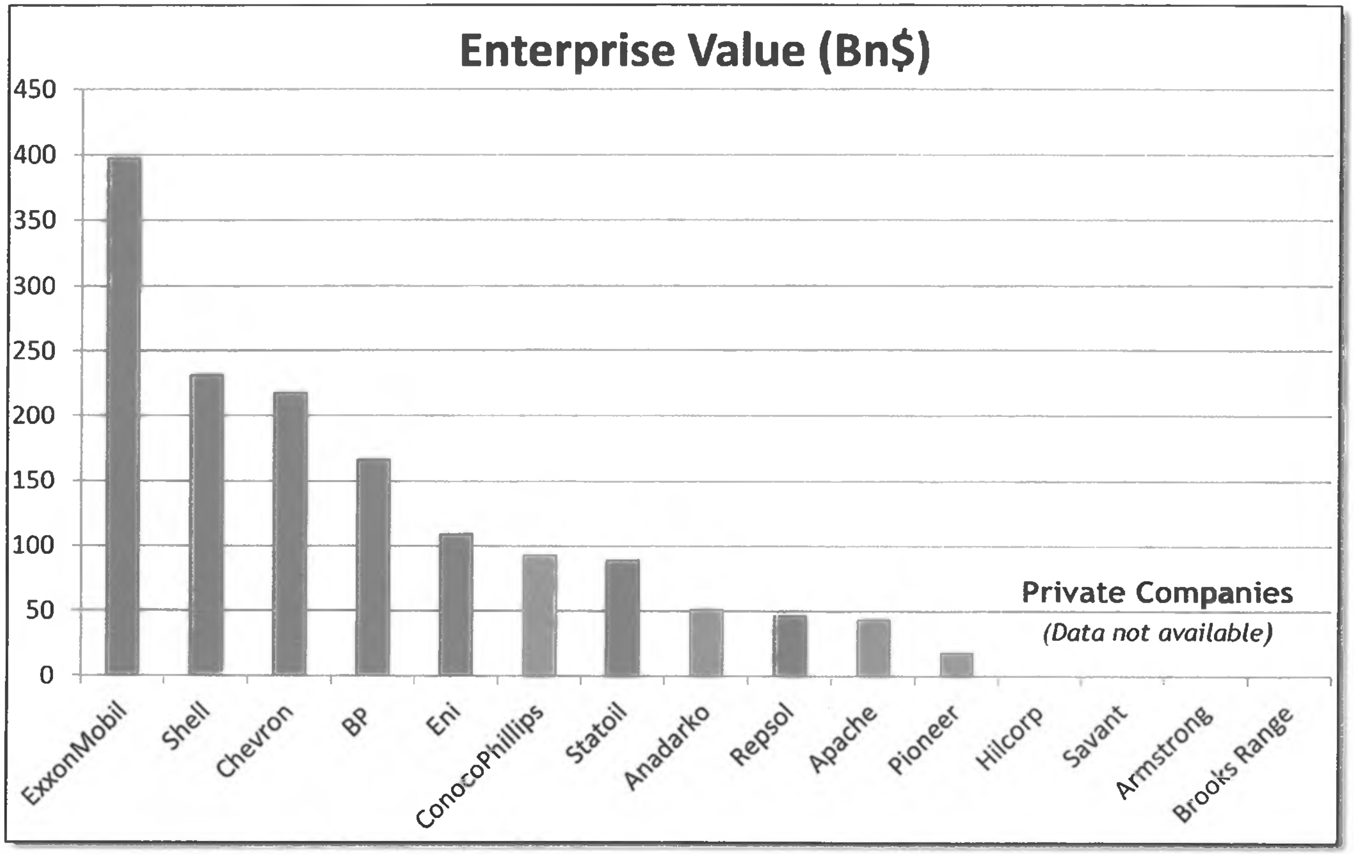
Eagle Ford Shale
$575 MM Drilling Program
116 MMBBOE Proved

2013 Production (Growth):
38-42 MBOEPD (+36% - 50%)

- > 40 rigs running
- > 20,000 drilling locations

Relative Rankings and Policy Considerations

PIONEER
NATURAL RESOURCES



Financial Market Drivers

Traditional Independents are rewarded for production growth and debt management

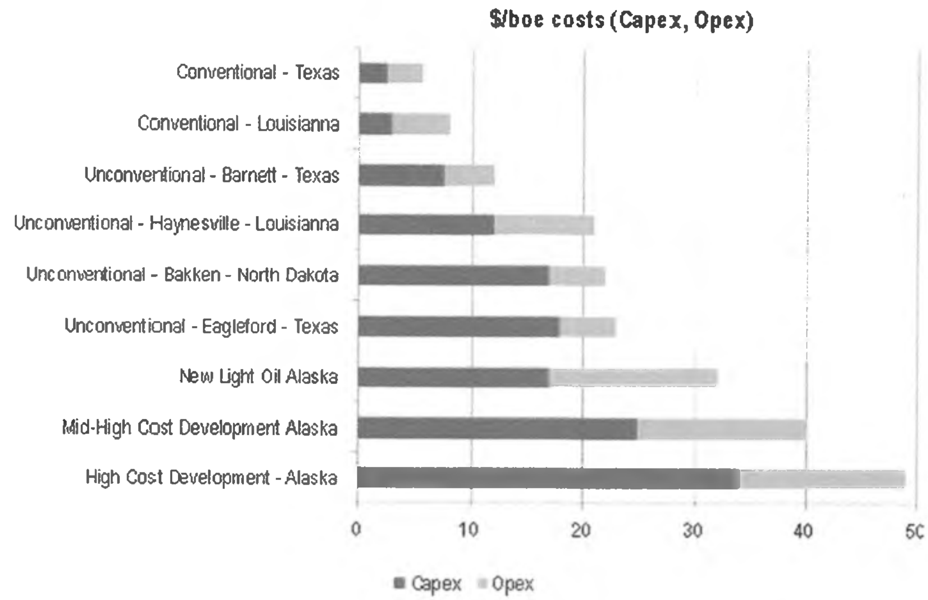
"While their [smaller Independents] production may not seem significant, their economic impact is. Some companies would have had to move their work to North Dakota if it wasn't for them."

~Doug Smith, president, Little Red Services, Testimony before TAPS Throughput Committee Jan 13, 2013

Eagle Ford Operators and Companies

PIONEER
NATURAL RESOURCES

■Abraxas Petroleum ■Alta Mesa Holdings ■Anadarko ■Apache Corp. ■Aruba Petroleum ■Aurora resources ■Austin Exploration (Aus-Tex Expl.) ■BHP Billiton ■BP ■Cabot Oil & Gas ■Carrizo Oil & Gas ■Chaparral Energy ■Chesapeake Energy ■Cinco Resources ■Clayton Williams Energy ■Comstock Resources ■ConocoPhillips – (Burlington Resources) ■CNOOC (China National Offshore Oil Corporation)■Crimson Exploration ■Devon Energy ■Eagle Ford Oil & Gas Corp. ■El Paso ■Enduring Resources ■Enerjex Resources ■EOG Resources ■Escondido Resources ■Espada Operating ■Exxon-XTO■Forest Oil ■GAIL (Gas Authority of India Limited) ■GeoResources Inc. ■Goodrich Petroleum ■Global Petroleum ■Hess Corporation ■Hilcorp Resources ■Hunt Oil ■Jadela Oil ■Japan Petroleum Exploration ■KNOC (Korea National Oil Corporation) ■Laredo Energy ■Lewis Energy Group (BP Partner) ■Lonestar Resources ■Lucas Energy ■Magnum Hunter Resources ■Marathon Oil ■Marubeni Corporation (Hunt Oil Partner) ■Matador Resources ■Mitsui ■Murphy Oil ■Newfield Exploration ■NFR Energy ■Penn Virginia Corp ■Peregrine Petroleum ■ PetroHawk ■ PetroQuest ■Pioneer Natural Resources ■Plains Exploration & Production ■Redemption Oil & Gas ■ Reliance Industries ■Riley Exploration ■Rock Oil Company ■Rosetta Resources ■San Isidro Development (Acquired by Chesapeake)■Sanchez Energy ■Sandstone Energy, LLC ■Saxon Oil Company ■Shell ■SM Energy (St. Mary Land & Exploration)■Statoil ■Strand Energy ■Strike Energy ■Swift Energy ■Talisman Energy ■Texon Petroleum ■Tidal Petroleum ■TXCO Resources (Now, Newfield & Anadarko)■Unit Corporation ■U.S. Energy Corp. ■Weber Energy ■WEJCO E&P ■ZaZa Energy



Source: Alaska Discussion Slides, PFC Energy 2012, February 11, 2013

http://eaglefordshale.com/companies/

Typical New Project Spend Profile

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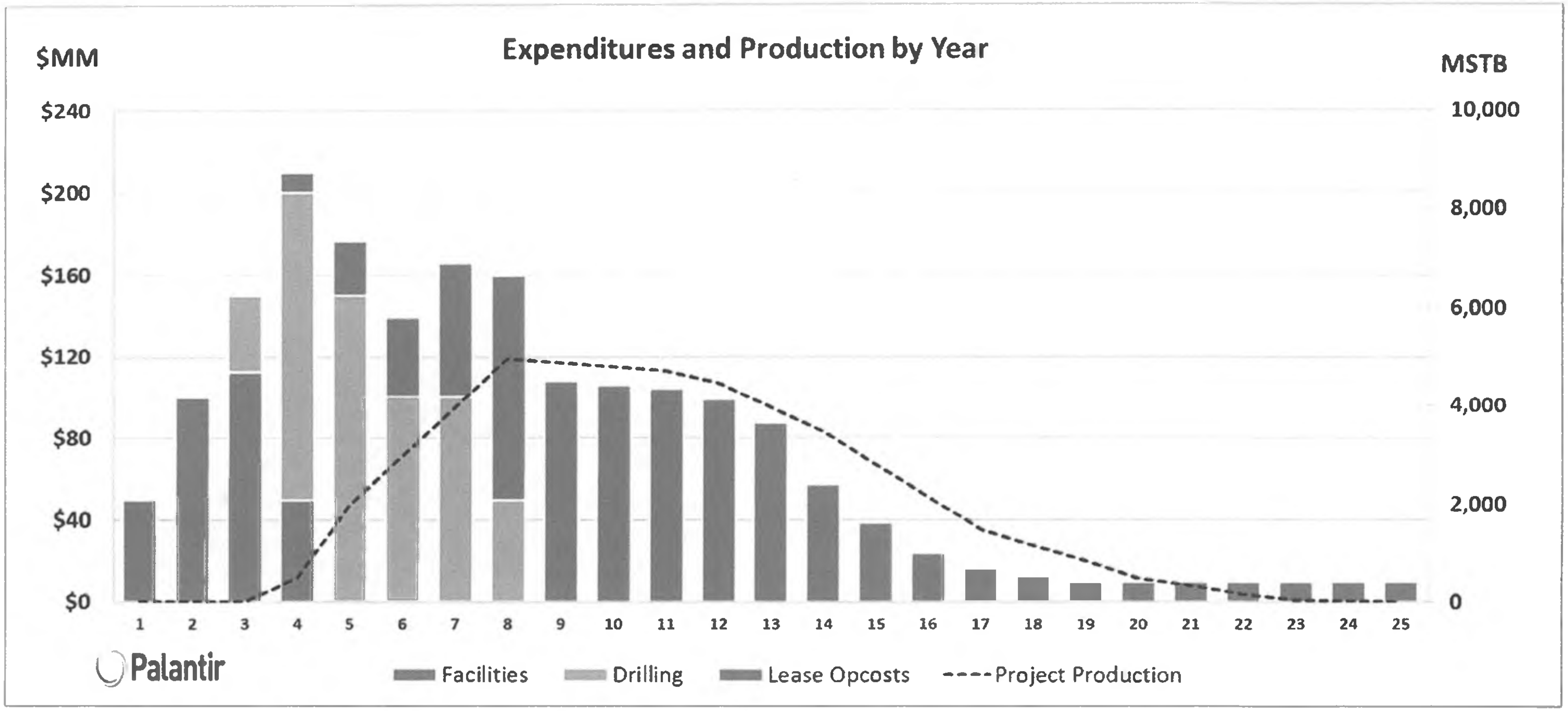
NATURAL RESOURCES



Typical Project (after discovery):

- 1st year: front end engineering work
- 2nd year: 100% of capital spent on facilities
- 3rd year: 75% capital is for facility work
- Drilling begins late in 3rd year, no production until 4th year
- 4th year: production begins
- Peak production rate occurs during 5th year after start of production

Fostering New Production: Why Credits Matter

PIONEER
NATURAL RESOURCES

- **Benefits to State**
  - Credits directly encourage activity in Alaska
    - Jobs, direct and indirect (9x multiplier)
    - More wells
    - More oil
    - More royalties, taxes and throughput
- **Benefits to Developer**
  - Reduces investor risk
  - Improves small project economics
  - Improves financial performance
    - Doesn't increase debt
  - Builds healthy industry
  - Strengthens competitiveness

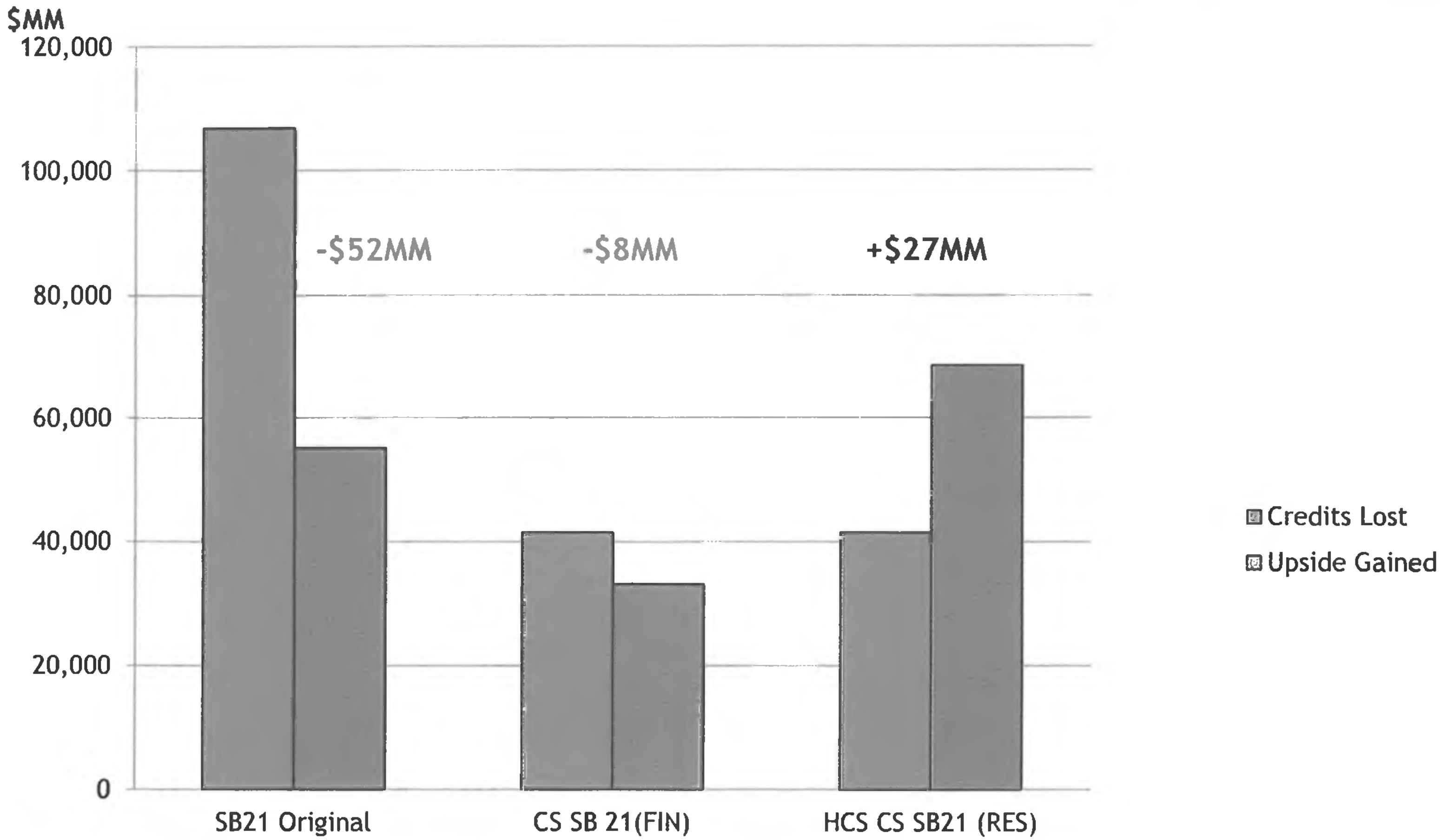
Loss Carry Forward Credit
- Redeemable / transferable
- Reduces upfront risk
- Assists new investment

Small Producer Credit
- Simple
- Predictable
- Improves project economics
- Low financial impact to State
- Included in original SB 21

$5 / bbl Credit
- Rewards production
- Levels government take

Mid Sized Producer Adding New Field

PIONEER NATURAL RESOURCES



New Field Assumptions:

- 50 MMBO field
- ~$1 Billion CapEx
- $10-$20/bbl variable OpEx
- $100 ANS West Coast (nominal)

HCS CSSB 21(RES) Closing Thoughts

PIONEER
NATURAL RESOURCES

- **Pros**
  - ✓ **33% Base / $5 bbl credit**
    - Keeps tax rate flat across price ranges
  - ✓ **GRE**
    - Rewards new oil production
  - ✓ **Small producer credit extension**
    - Levels playing field
  - ✓ **Loss carry-forward credit monetization**
    - Rewards investment in Alaska
- **Cons / 'Wish List'**
  - – Elimination of capital credits
  - – Increase GRE for challenged leases to 30%
  - – Add targeted credits for facilities/well related costs
- **HCS CSSB 21(RES)**

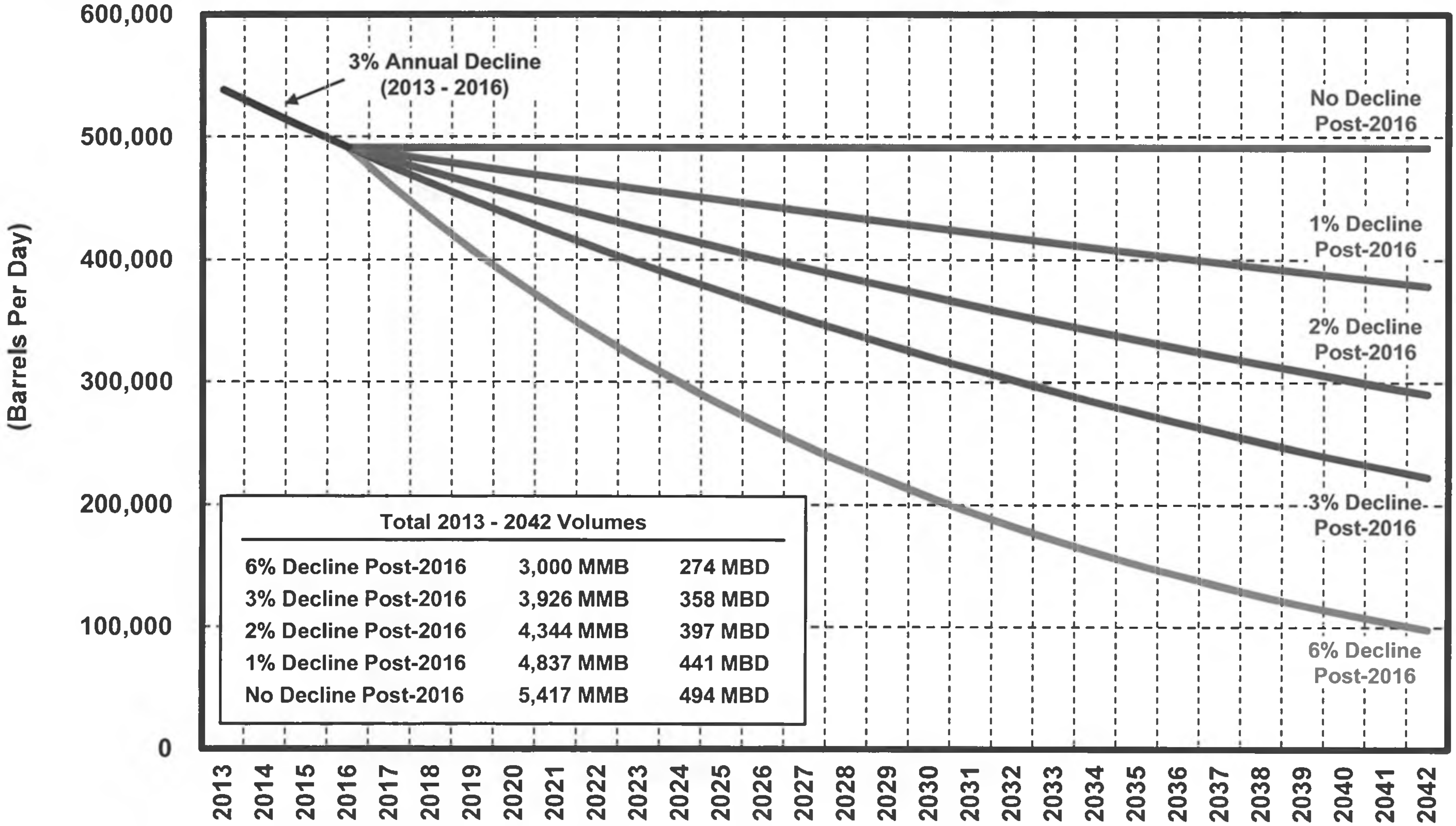
4/9/13 afternoon

Additional Comments on HCS CS SB21 (RES)

Barry Pulliam
Managing Director
Econ One Research, Inc.

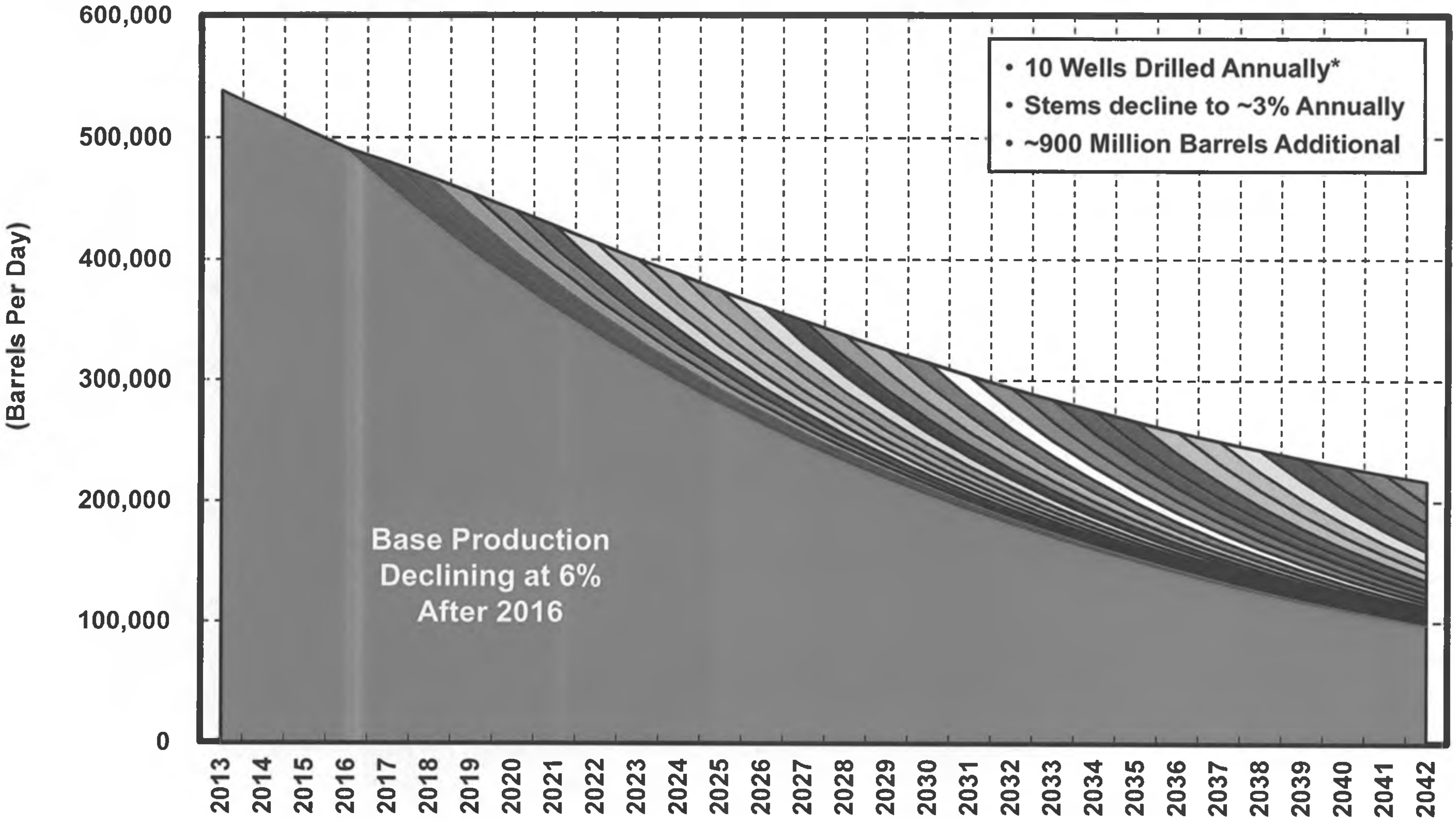
April 9, 2013

North Slope Production Scenarios 2013 - 2042



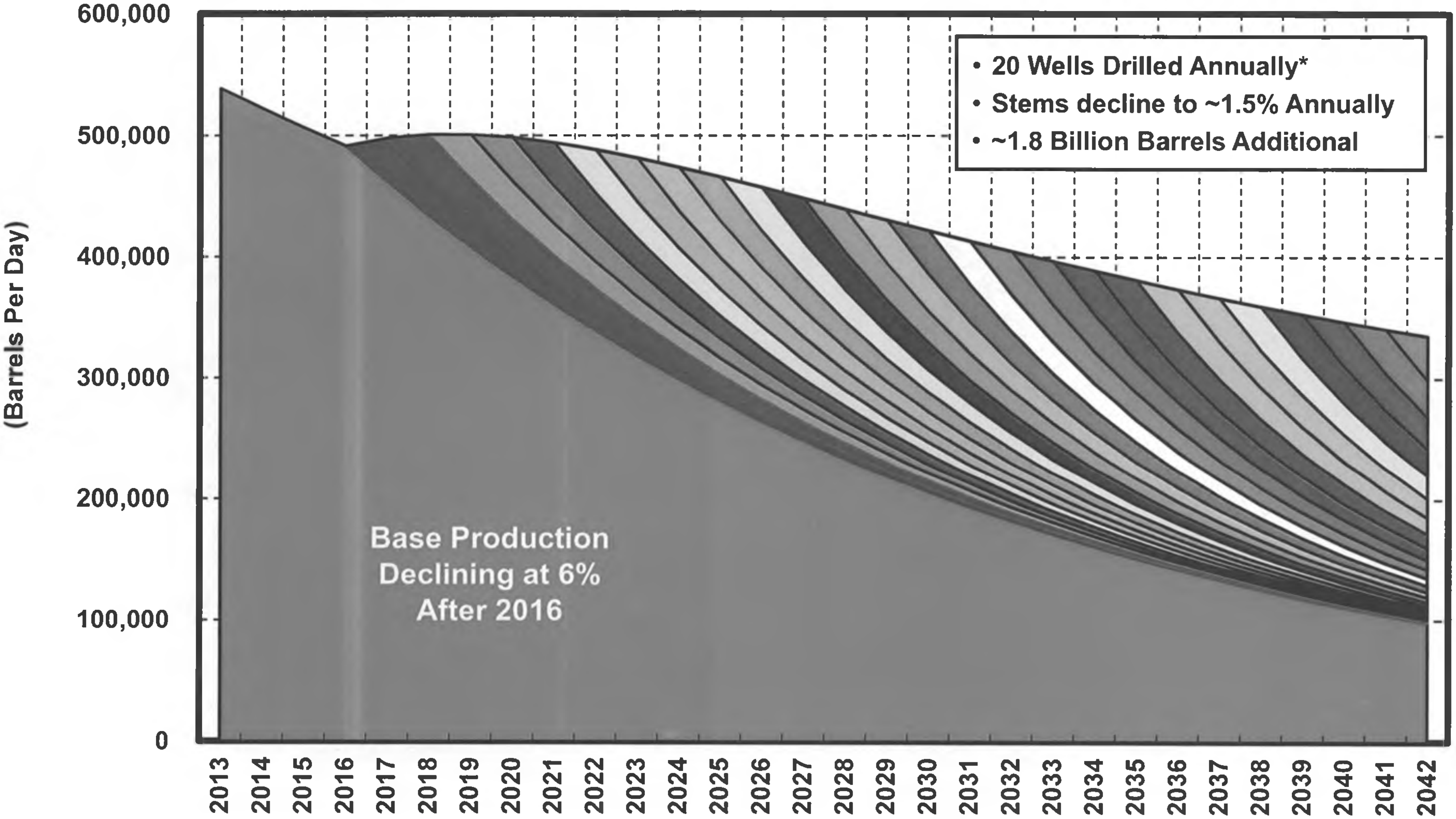
Note: These are intended to illustrate potential production scenarios. They are not a forecast of actual production.

Impact of New Drilling* on Production
10 New Wells Drilled Annually
2013 - 2042



New field development: 1,800 BPD Initial Rate, 15% Decline Rate.
Note: This is intended to illustrate potential production scenarios. It is not a forecast of actual production.

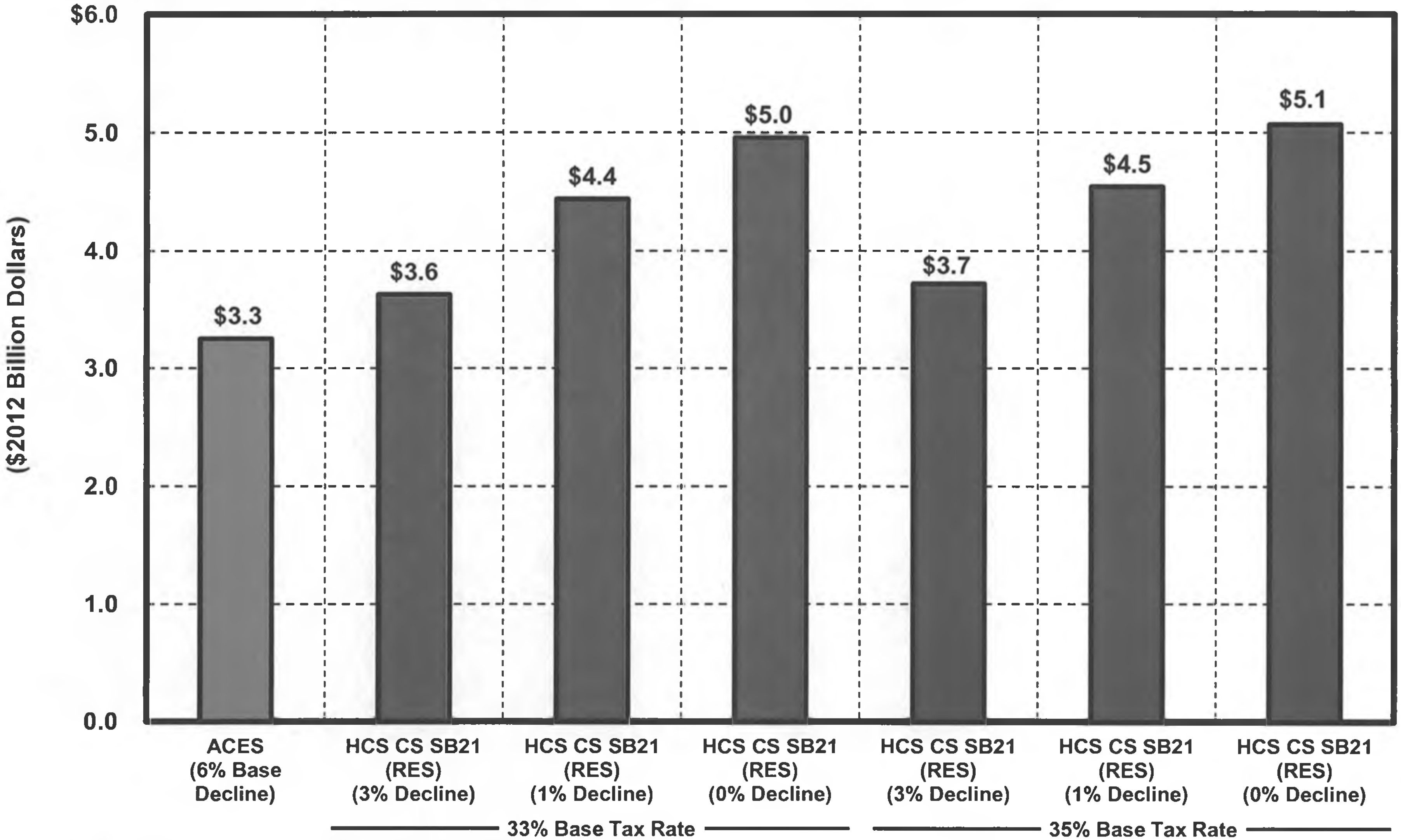
Impact of New Drilling* on Production
20 New Wells Drilled Annually
2013 - 2042



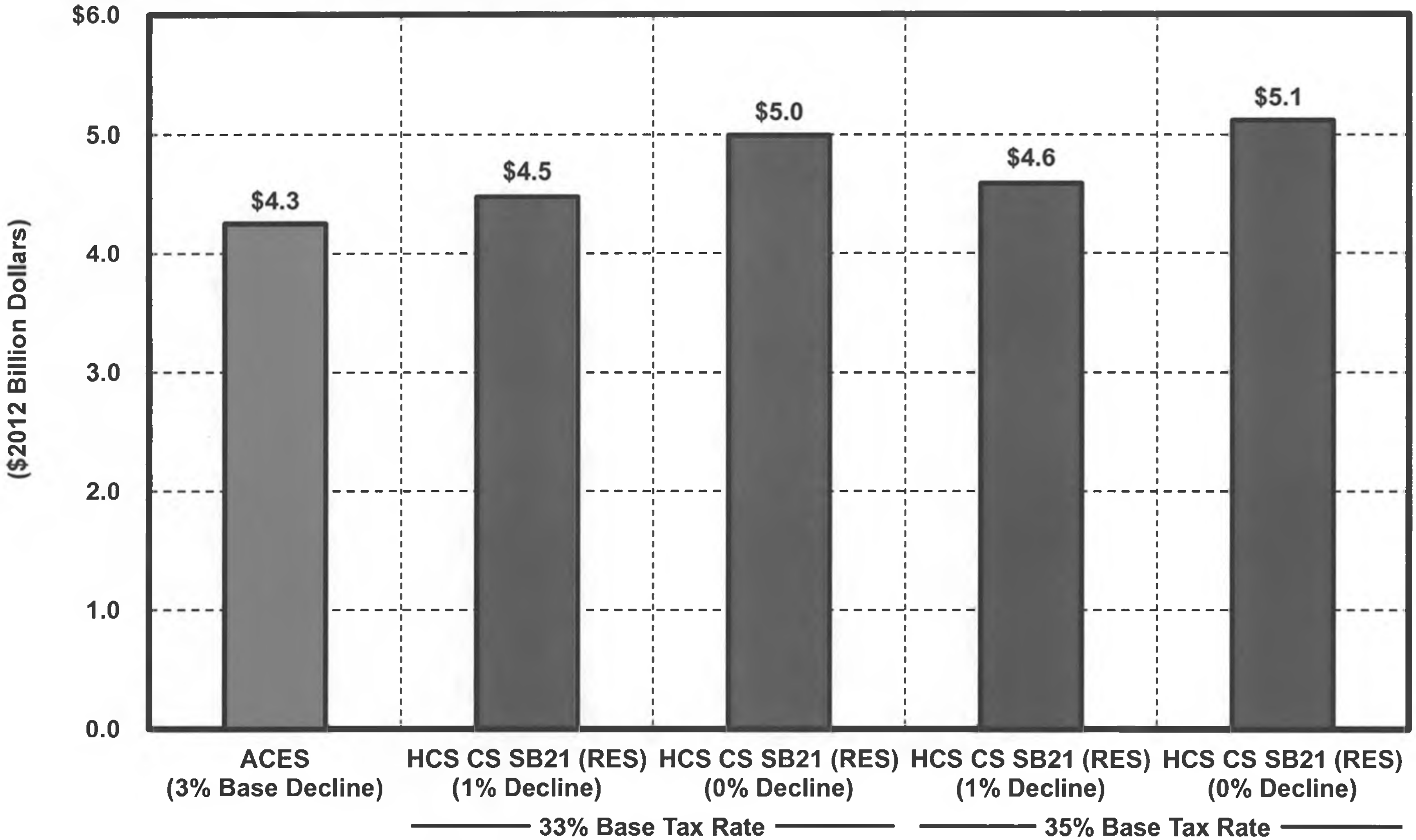
New field development: 1,800 BPD Initial Rate, 15% Decline Rate.

Note: This is intended to illustrate potential production scenarios. It is not a forecast of actual production.

Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (RES) $100 West Coast ANS ($2012)



Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios
ACES v. HCS CS SB21 (RES)
$100 West Coast ANS ($2012)



Brooks Range Petroleum

House Finance Committee
Comments on SB 21

Investors: AVCG (Alaska Venture Capital Group)
Operator: Brooks Range Petroleum

Ken Thompson
AVCG Co-Owner/Investor
Former President, ARCO Alaska, Inc.

April 9, 2013

AVCG LLC

Brooks Range Petroleum

Why Consider Our Company's Perspectives ?

Brooks Range Petroleum

1) Most active exploration company exploring and developing solely on North Slope state lands
   a) Drilled 10 of 36 exploration wells on state lands in 2007-12 (more than COP, BP, XOM, ENI, Repsol, Armstrong combined)
   b) 105,000 leased acres in 3 core areas in JV partnership with Ramshorn Exploration (affiliate of large Nabors Industries)

2) ~ $200 MM invested to date in Alaska North Slope projects...3 discoveries, acquired discovery

3) Mustang development project under construction...$577 MM capital, 44 MMBO, 15,000 BOPD... future level of capital spending/yr same as Pioneer Natural Resources and one-third the level of COP capital spending

4) Three other development projects in permitting/conceptual engineering stages...> $1.5 B capital

5) First production and cash flow to state and our companies...startup of Mustang in 3Q 2014

6) On investment of $200 MM, received refunded tax credits totaling $69 MM but State will receive back this amount+ in the first year of Mustang production...and $1.2 billion over field life
   a) All credits have been redeployed on the North Slope for new drilling or seismic to find, develop oil...none sent Outside
   b) Credits redeployed has allowed in some years the drilling of 3 exploration wells instead of 2...or 2 wells instead of only 1
   c) Payment of credits in cash versus just an allowance against taxes critical to AVCG which has no current production

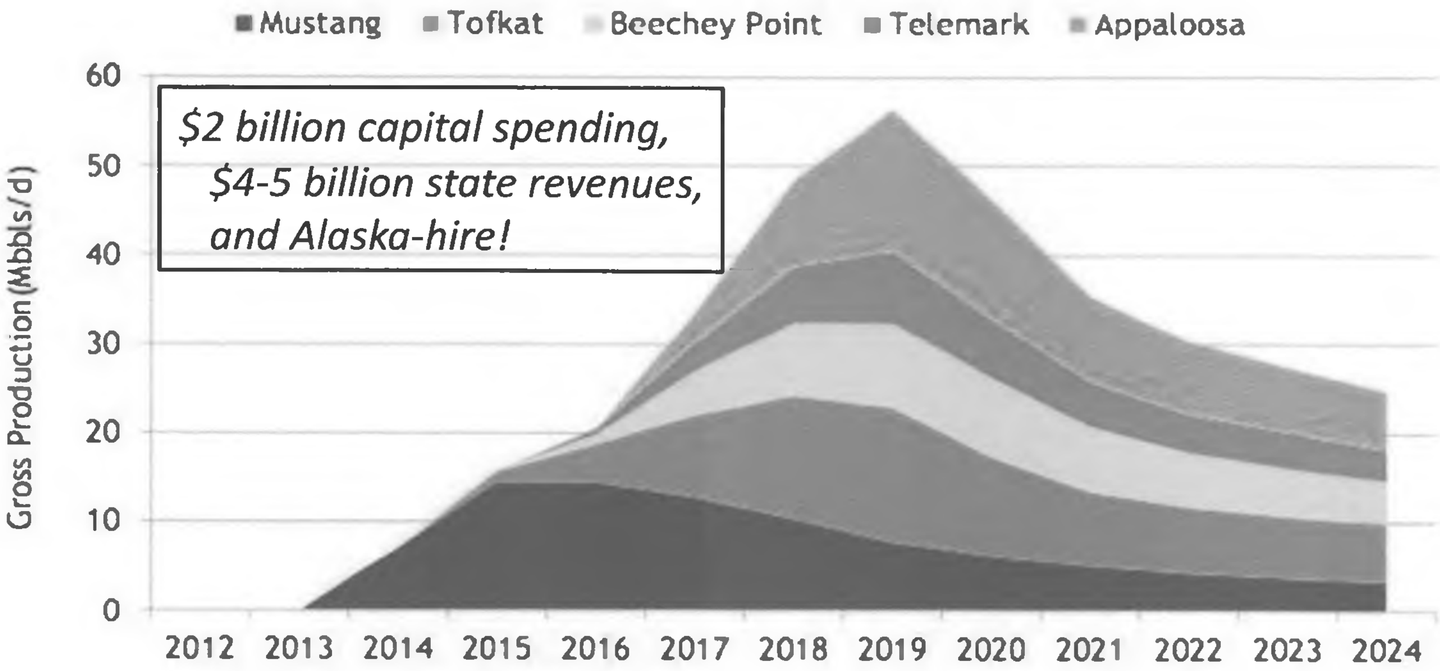
7) Experience in bringing other independents to Alaska and in raising capital for Alaska
   a) Seeking additional capital for Mustang and 3-5 year exploration program...started fundraising 18 months ago, Sept 2011
   b) Sent materials to 210 firms, but only 19 wanted to consider Alaska...and after further review, only 2 firms remain interested
   c) Biggest hurdles we heard: 1) complex and high gov't take of AK fiscal regime, 2) flow of capital to Lower 48 source rocks
   d) Two firms remain and we hope to finalize deal...belief in our confidence that Legislature will make positive change in 2013

What Difference Can Our Company Make?

Brooks Range Petroleum

Production Profile
(Mbbls/d)

"New work in existing fields to increase production above their existing declines will not – by itself – level AK's oil production. Production from exploration discoveries are needed also. Alaska still needs E&P...not just P!"



*Between 2012 and 2011, North Slope oil production declined 50,768 BOPD. Developments such as the above, if repeated, could help in replacing production fall off...**AND ACHIEVE "NO DECLINE!"***

Note: Mustang delineated and development underway. Tokfat, Beechey Point, Telemark, Appaloosa require delineation before sanctioning...not risked.

We See Positives In SB 21 To Make Alaska More Competitive

Brooks Range Petroleum

1) Eliminates progressivity factor, increases base tax rate from 25% to 33% but provides $5/bbl produced bbl credit
   - ✓ *POSITIVE: Eliminating progressivity simplifies tax calculation and will be a public relations plus for AK*
   - ✓ *NEGATIVE to POSITIVE: Base tax rate went from 25% to 35% not expected…a balance at 33% now in bill is reasonable*
   - ✓ *POSITIVE: $5 produced bbl credit better balances relative state/producer takes at low oil prices and flat take at higher prices*

2) Increases "Carry Forward Loss Credit (CFL)" from 25% to 33% and is monetizable and transferrable
   - ✓ *POSITIVE: incrementally more future cash flow to re-deploy into facilities & drilling*

3) SB 21 originally extended "Small Producers Credits" from 2016 to 2022…reduces small producers' tax bill by $12 MM/yr…and latest version keeps the SPC extension to 2022 which is very positive for new players
   - ✓ *NEGATIVE TO POSITIVE: **SPC REINSTATED TO 2022**…more cash flow for small producers to re-deploy into facilities & drilling*

4) Specifies 20% QCE tax credit certificate payment in 1 year vs. 2 but does eliminate QCE on 12/31/13 on NS only
   - X *NEGATIVE: goes away 12/31/13 on North Slope…for BRPC, no QCE thru 2015 to redeploy into Mustang development project*
   - ✓ *POSITIVE: **IF EXTENDED** to 12/31/15 for at least small producers…Mustang project was sanctioned assuming QCE…but OK to limit QCE per company per year to $50MM in order to control impact on state treasury. Been helpful to CI small producers!*

5) For new oil, introduces "20% Gross Value Reduction (GVR) " and amends definition of leases that can be included for this GVR 43.55.160…
   - ✓ *POSITIVE: Should incentivize and rewards new oil production on more leases, also helps during low oil price cycles*

6) SB 21 originally had a 30% "Exploration Incentive Credit" for NS exploration wells drilled that target new oil discoveries regardless of location…similar to Cook Inlet…please re-instate this through 12/31/18 but OK to cap
   - X *HUGE NEGATIVE: Doesn't matter to legacy field owners, but a huge negative for small exploration companies like ours*
   - ✓ *HUGE POTENTIAL POSITIVE: **REINSTATE THIS CREDIT**, but to minimize impact on state treasury, limit to $25 MM credit per year per company…and limit the time for five years through 2018 then "retest" if incentive has generated more exploration*

Photos: Mustang Development Project Underway - $1.2 B State Revenues

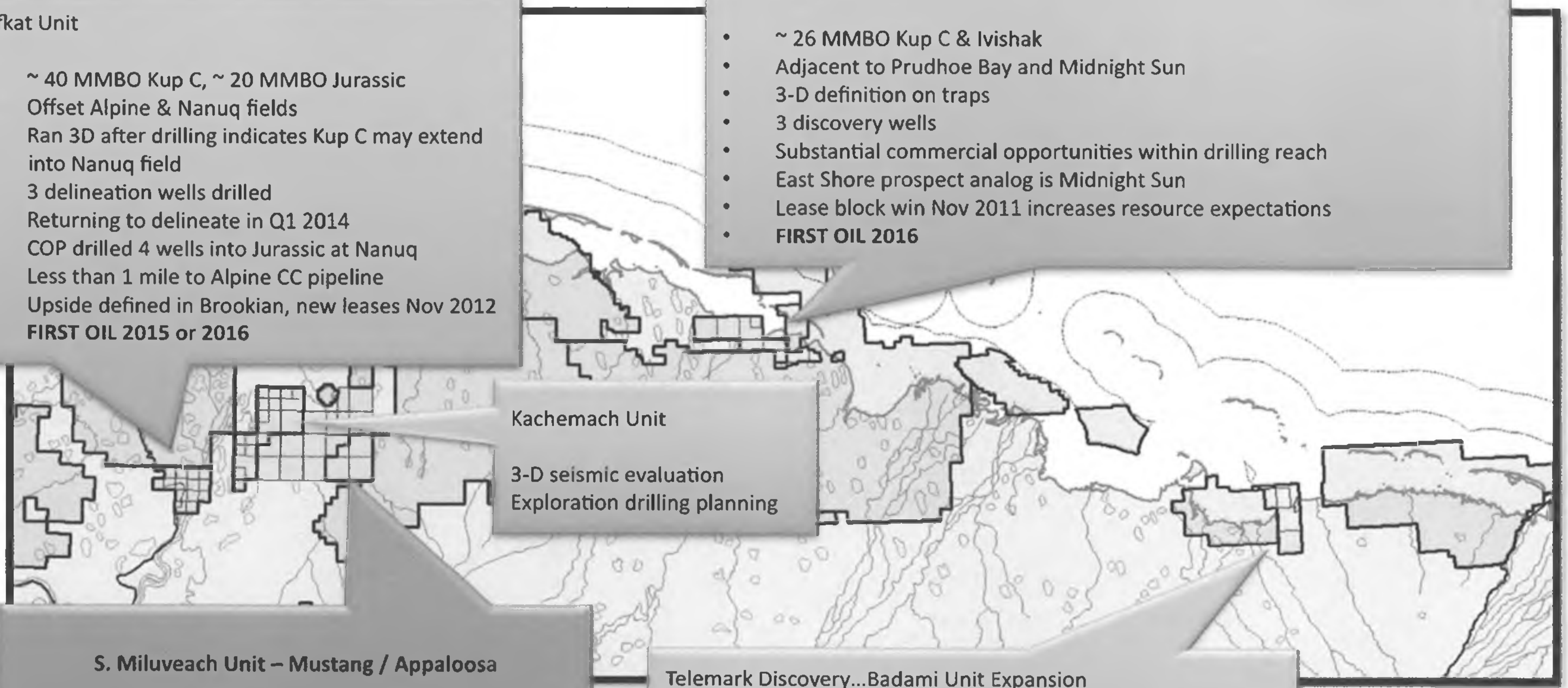
Brooks Range Petroleum

Photos: Mustang Development Project Underway - $1.2 B State Revenues

Brooks Range Petroleum

BRPC North Slope Drilling Results And Success

Brooks Range Petroleum



Tofkat Unit

- ~ 40 MMBO Kup C, ~ 20 MMBO Jurassic
- Offset Alpine & Nanuq fields
- Ran 3D after drilling indicates Kup C may extend into Nanuq field
- 3 delineation wells drilled
- Returning to delineate in Q1 2014
- COP drilled 4 wells into Jurassic at Nanuq
- Less than 1 mile to Alpine CC pipeline
- Upside defined in Brookian, new leases Nov 2012
- **FIRST OIL 2015 or 2016**

Beechey Point Unit

- ~ 26 MMBO Kup C & Ivishak
- Adjacent to Prudhoe Bay and Midnight Sun
- 3-D definition on traps
- 3 discovery wells
- Substantial commercial opportunities within drilling reach
- East Shore prospect analog is Midnight Sun
- Lease block win Nov 2011 increases resource expectations
- **FIRST OIL 2016**

Kachemach Unit

3-D seismic evaluation
Exploration drilling planning

S. Miluveach Unit – Mustang / Appaloosa

- 44 MMBO Kup C Mustang, ~ 37 MMBO Appaloosa
- Extension to KRU field
- N Tarn well penetrated reservoir 2011, re-entered & tested 2012 (20+ Kup C discovery)
- N Tarn #1A confirmed quality C sand 10+ ft. oil test
- Drilled confirmation Mustang #1 2012 20+ ft.
- Confirmed communication with KRU 2M
- Common carrier pipeline 700' from production pad
- 200 sq. miles proprietary 3D + 240 WBA license 3D
- **FIRST OIL 2014**

Telemark Discovery...Badami Unit Expansion

- ~ 16 MMBO Flaxman Sst
- Project area located between Badami & Pt. Thomson
- E Mikkelson #1 tested 250 BOPD un-stimulated
- Improved reservoir setting to Badami
- Horizontal development strategy
- Facilities and pipeline capacity in close proximity- no need to build facilities
- Pt. Thomson sand upside
- **FIRST OIL 2015 or 2016**

Alaska Oil and Gas Association

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907) 221-1481 Fax: (907) 279-8114

ALASKA OIL AND GAS ASSOCIATION
TESTIMONY ON HCS CSSB 21(RES)
TO THE HOUSE FINANCE COMMITTEE

April 9, 2013

Good Morning. My name is Kara Moriarty and I am the Executive Director of the Alaska Oil and Gas Association, commonly known as "AOGA". AOGA is the professional trade association that represents 15 member companies accounting for the majority of oil and gas exploration, development, production, transportation and refining of oil and gas onshore and offshore in Alaska. These comments regarding the House Resources Committee Substitute for Committee Substitute for Senate Bill 21 have been reviewed by all our members and approved unanimously.

Overview. Alaska's greatest challenge today, which industry shares with the State, is the decline of oil production from the North Slope. As with any non-renewing resource, it gets more and more expensive to produce the next barrel of oil or Mcf of gas as a field is depleted, and inevitably you one day reach a point where the cost of producing the next barrel or Mcf will exceed the value of production, and production will cease. This destiny was the certain fate of the Prudhoe Bay field even when it first came into production in 1977. At that time the best estimate for its total oil production was 9.6 billion barrels. But last October it produced its 12 billionth barrel, and there is a good chance for an additional 2 billion barrels or more. These facts illustrate how much expectations can change as a result of new investments and projects to increase the total recovery from a field. We believe opportunities similar to this are still possible in the future, both for legacy fields and for others that have more recently come into production. To realize this potential, though, these opportunities must win the competition against opportunities elsewhere for a finite pool of investment dollars.

With respect to oil and gas taxes, the great issue facing Alaska is that there is a fundamental trade-off between short-term and long-term benefits and results for Alaskans. At one extreme, if the tax is 100%, the State would have the greatest possible share, but nothing to be sharing in. And at the other extreme, Alaskans would enjoy the greatest possible development of their resources and the greatest economic activity from that development, but their state government would have no tax revenue from that activity if the tax rates are zero. Clearly, as Alaska comes down from a 100% rate, there becomes more and more production available to tax, and initially the state's tax revenue increases over all even though the tax rate becomes less. Yet the zero-percent example shows the State can overshoot the mark. The challenge for the State and you, in particular, as the Legislature lies in striking a balance between the size of the economic development activity that occurs and the rate of tax applied to that activity.

Our role is to share with you our perspective about how close Alaska is to having such a balance. And, frankly, Alaska is too far toward overtaxing and shrinking the economic "pie" available to be shared in the future. AOGA has testified, individual companies have testified and even the consultants hired by you and the Administration have testified that the present tax system is not competitive with the opportunities industry has elsewhere.

AOGA has heard a lot of concern, and so have you, that there is – quote – "no guarantee" – unquote – that Alaska will see any increase in industry spending and activity if the State changes its tax system to make investment opportunities here more competitive. As a former elementary school teacher, I see this as unfounded. It would be like saying you don't to cut the stem of an apple hanging from a tree, without a guarantee it will fall to the ground.

Just as the Law of Gravity will make that apple fall without any stated guarantees, so there is a similar law — an economic law of business — that assures a positive response if you make Alaska more competitive. This law of business is the principle of making the most for the shareholders' money. Right now the present tax regime is not competitive with opportunities elsewhere, and so money gets invested elsewhere in order to get more for the shareholders' money. But if Alaska makes its opportunities better than Outside competition by reforming the taxes, it stands to reason that more investment will be made here because a greater number of Alaskan opportunities could then make more for the shareholders' money than the competition. And this 'gravitational attraction' to invest here becomes stronger as prices increase. Even my former students would understand that if I will let them have more jelly beans for a nickel than the teacher down the hall, they will give their nickels to me. If a restructuring and tax rate reduction make investments here more competitive, companies will want to make more investments here, even if there are no specific guarantees. Their shareholders will demand it.

What the House Resources CS would do. *Progressivity repeal.* Both the Senate-passed Bill and the House Resources CS for it would repeal the ACES progressivity, which would be a material step forward for three reasons. First, progressivity under ACES takes away too large a share at current prices, at about \$100/barrel the tax rate is just over 40%. Second, progressivity guts the upside potential for Alaska investments, which is the one economic advantage that Alaska's remoteness offers. This happens because, the more that the upside is realized, the more of it progressivity takes away and not just from the upside, but from the \$30 baseline value as well. And third, as BP explained in its testimony to the House and Senate Resources Committees on February 20, when you have a plan of development with several elements in it, progressivity makes it impossible to analyze and quantify the tax effect of any single element because the progressivity for all of the elements together is greater than the sum of the progressivities for each one separately.

Base tax rate increase. The House CS would raise the base tax rate from 25% to 33%, while the Senate's version would raise it to 35 percent. Either would be a step in the wrong direction because we have consistently testified that the present 25% rate is too high even without progressivity. We are also concerned that a 33% or 35% rate could end up setting an inappropriate kind of "floor" on state tax expectations for future oil or gas developments, even though they might have very different economics from the ones that have been analyzed for Senate Bill 21. Obviously, if AOGA were forced to choose between a 35% rate and a 33% one, we would choose 33%, but nonetheless something lower would be even better. A lower rate would be better for Alaskans, not just for industry, because of the business counterpart to the Law of Gravity that I discussed earlier, which will attract additional investment here.

Tax credits and the gross-revenue reduction for new production. The House Resources CS would phase out the present 20% "qualified capital expenditure" or QCE tax credit at the end of 2013 for North Slope expenditures. If this were standing alone, AOGA would be against it. But the House CS offers other incentives that tend to offset this loss of the QCE tax credit.

For new production, that is, production from units containing no land that had been unitized as of January 1, 2003, or from a participating area established after 2011 and within a pre-2003 unit that contains a reservoir that had already been in a participating area before December 31, 2011, or from acreage added to a participating area after 2013, the gross revenue from this new production would be reduced by 20% in computing the gross value of the point of production (GVPP), and there would be a tax credit of $5 per barrel for oil falling in any of these new-production categories. For all other North Slope oil production, there would be a "sliding scale" tax credit starting at $8 a barrel when the GVPP is less than $80 a barrel. The credit would decrease by $1 a barrel for each $10 increment above that, reaching zero when the GVPP per barrel is $150 or more. In doing this the House Resources CS fills a gap in the Senate-passed version of the Bill, by providing a tax incentive for the 80 – 90 percent of the remaining oil potential that is within Alaska's jurisdiction to tax and within its control to develop or not develop, as it may choose.

The House CS would also change the exploration credit under AS 43.55.025 by removing the distance-from-the-nearest-well requirement in (c)(2)(B) for middle Earth exploratory wells. We believe the removal of the distance requirement should be extended to the North Slope as well.

In addition, the House CS would delay the sunset of the small-producer tax credit from 2016 to 2022, which is something AOGA has specifically advocated for in our testimony to other committees regarding Senate Bill 21 and its companion, House Bill 72. This extension was included in the original SB21 and we believe the administration showed wise policy judgment in their decision to do so.

Lastly, the House Resources version maintained the change to the loss carry-forward (LCF) annual loss credit allowing companies that spend more money than they make in Alaska to take the loss in the form of a credit that is redeemable by the state or transferrable to another taxpayer. AOGA believes this particular credit is extremely valuable to the current and any new small producers in reducing the upfront risk associated with new field development. The rate for the LCF credit as a matter of policy by the administration, has matched the base rate at 33% under the House Resources CS.

AOGA does not believe the State's tax policy should create winners and losers among taxpayers without a very sound reason for doing so. As a matter of general principle, therefore, we would support the new tax credits being proposed in the CS, the extension and broadening of the existing small-producer and exploration tax credits respectively, the gross-revenue reduction and $5 a barrel tax credit for new production, and the sliding-scale tax credit for legacy production. And we would oppose the sunset of the QCE tax credit at the end of this year if the tax credit was standing alone. To the extent, however, that these different measures and other provisions in the House Resources CS may be seen as trade-offs against one another, different provisions have different degrees of importance for individual members of AOGA. Accordingly, we refrain from expressing views about whether any such trade-off is good or bad overall, and we leave it to individual companies to offer their own opinions on such questions if they choose to do so.

Statutory interest on tax underpayments. The House Resources CS addresses a concern we have raised in our earlier testimony on SB 21 and House Bill 72, that a six-year statute of limitations for auditing and a minimum interest rate of 11% compounding quarterly can nearly double-up any underlying tax liability that the audit may find. The heightened risk this causes is a material factor in terms of Alaska's competitiveness relative to other places. That risk — and not just the reward that an investment can make under the tax laws — is an integral element in an investor's comparison of investment opportunities here versus elsewhere. We endorse this change, which serves to compensate the State reasonably for any lost use of funds that it suffers from a tax underpayment.

We would point out to you, however, that the House Resources CS does not address the interest rate under AS 43.05.280(a) for tax overpayments, which provides "Interest shall be allowed and paid on an overpayment of a tax under this title at the rate and in the manner provided in AS 43.05.225(1)." This reference to AS 43.05.225(1) should be changed to parallel the changes that the CS makes to other sections that refer to AS 43.05.225(1).

Joint-interest billings ("JIBs"). The question of using JIBs as the initial source for a taxpayer's lease expenditures is not about how much a taxpayer will be able to deduct. It is about how effectively the Department will administer the tax, and about how producers can comply with it.

Consider the situation of a producer who owns part of a field but is not the operator of that field. Unless and until the non-operators audit the JIBs they have received from the operator, the only information they have about how much is being spent, and for what, is the information provided by the operator in support of the JIBs, plus the annual budget for the field that the operator proposed and they approved. Without any detailed back-up documenting the cost items being invoiced in the JIBs, how can a non-operator know whether a particular cost-item that it has been billed for is actually deductible as a lease expenditure?

A non-operator in this position would be a lot like you or me regarding our home mortgage payments if we didn't have a year-end statement from the bank itemizing how much we paid as principal, how much as interest, and how much of the escrow was paid for property tax. We would know the total amount we paid to the bank, but we wouldn't know how much to itemize on our tax returns as mortgage interest and property tax. The non-operator is in a similar position of not having the information needed to figure out how much of the JIBs it paid is deductible and how much isn't. Yet this is how the ACES tax currently operates.

Now consider the situation from the tax-enforcement side, where the Department is auditing the claimed lease expenditures for a field with an operator and three non-operators. Typically, the Department will send different auditors to each of these four companies. Once there, the auditor will find that a non-operator doesn't really have any detailed books and records to determine whether the non-operator's lease expenditures based on the JIBs from the operator actually qualify as allowed lease expenditures. Thus the non-operator has to try to get access to those underlying books and records from the operator so the auditor can see them. This means the Department audits the same underlying set of books and records four times, once for each of the three non-operators, and again in the audit of the lease expenditures the operator itself claimed for tax purposes. And it also means the operator has to support each of the non-operators in their audits in order for them to show the non-operators' claimed lease expenditures were allowable.

Throughout the Department's two-and-a-half-year process of writing regulations to implement ACES, AOGA consistently said the Department ought to audit the system of accounts that the operator maintains under the joint-interest billing agreement. In that audit, the Department could apply exactly the same standards it has established by regulation to determine which particular accounts or cost-codes in the system are allowed or not allowed. The Department could share the results of that audit with all the owners of that field, informing them which cost-codes or accounts are not deductible. This would allow each participant in the field, including the operator, to report and pay its tax liability correctly without deducting anything from the disallowed cost-categories and accounts. Audits of the non-operators would simply be a verification that they did not deduct any of the disallowed costs. And after the first audit of the system of accounts which the operator maintains, the audit of the operator and its system of accounts for joint-interest billings for that field would simplify to a verification that the same kinds of data are still flowing into the same cost-codes and accounts, with an examination of any new accounts or cost-codes to determine whether or not they are deductible.

The Department readily could set up this much more efficient way to administer the tax by regulation. And its auditors are naturally unwilling to adopt an audit approach that falls outside the four corners of what the regulations currently provide for. The House Resources CS would enact the substance of AS 43.55.165 (c) and (d), and thus restore the original statutory authority that the

Department earlier said it lacked. If the Department then used this regained authority to administer the tax as efficiently as it could, a great deal of uncertainty and wastefulness in the current way the tax is being administered could be avoided.

What the House Resources CS would NOT do. There are several areas of the current production tax AOGA believes should be changed to make it a more efficient tax that are not addressed in the current bill, but in the interest of time, I want to briefly mention three specific problem areas:

1) Six-year statute of limitations. Even if the interest rate on tax underpayments is changed, a six-year statute of limitations will remain. The three-year statute under AS 43.05.260 works perfectly well in practice for all of the other taxes an industry participant pays, because it allows the three-years to be extended repeatedly by mutual agreement of the Department and the taxpayer.

2) Costs to respond to an "unscheduled interruption ... or reduction in ... production" or an "unpermitted release of a hazardous substance or [natural] gas". AS 43.55.165(e)(19) disallows costs incurred "in response to ... [an] unscheduled interruption ... or reduction in the rate of ... production" or to an "unpermitted release of a hazardous substance [such as crude oil] or [natural] gas[.]" This disallowance causes problems because there are no standards of materiality for determining whether it applies or not. We are not asking you to try to write the answers to these questions in the statute. We suggest, instead, that you expressly give the Department of Revenue the duty to adopt regulations that set reasonable thresholds for materiality about how long an "interruption" has to last, about how large a "reduction" in production has to be, about how much an unauthorized release has to be or in what circumstances must it occur, and about how much the cost "incurred … in response to" such situations has to be in order trigger a disallowance under AS 43.55.165(e)(19).

3) Transportation costs for regulated pipelines. The ACES legislation in 2007 amended AS 43.55.150, the statute that determines the gross value at the point of production on the basis of destination prices or values minus the costs of transporting the oil or gas to those destinations from its point of production in the field. This is known as the netback approach. AOGA is not objecting to the netback approach itself. Instead, we are concerned about the amended version of AS 43.55.150, which provides that "[i]f the department finds that ['a shipper of oil or gas is affiliated with the transportation carrier'] ..., the gross value at the point of production is calculated using the actual costs ... or the reasonable costs of transportation as determined under this subsection, whichever is lower." This concern arises specifically in the context of pipelines whose carriage of oil or gas in intrastate commerce is regulated by the Regulatory Commission of Alaska (the "RCA") and whose carriage of oil or gas in interstate commerce is regulated by the Federal Energy Regulatory Commission ("FERC").

We believe the cost for transportation through a regulated pipeline should be the tariff the RCA or FERC allows that pipeline to collect. If the tariff turns out not to have been correct, the RCA or FERC will remedy that through a refund order. There is no need for the Department of Revenue to restate a regulated tariff on the basis of what it, the Department, thinks the tariff should be. We believe the statute should say that "tariff rates that a regulated carrier is allowed to collect by the Regulatory Commission of Alaska or another regulatory agency are reasonable for purposes of this section."

Conclusion. In terms of structurally reforming the present ACES tax, the House Resources CS has considerable technical merit. Its repeal of the high ACES progressivity would eliminate a great deal of complexity in the tax and uncertainty in analyzing the tax effects on projects. Its reform of the interest rate for tax underpayments would significantly reduce the risk from tax underpayments being doubled-up by the interest after a six-year audit. It would extend or broaden existing tax credits for small-producers and the exploration provisions, and it would create a gross revenue reduction and a system of per-barrel tax credits that is directed to new development and production as well as more production from legacy fields on the North Slope. And it would restore the Department's clear authority to administer the tax in a more efficient and effective way by using joint-interest billings as a tool for compliance, while at the same time rigorously auditing those billings to prevent the deduction of billed cost-items that are not deductible under the tax.

The principal downside we see in the House Resources CS is the tax rate. We believe even a 33% rate falls on the high side of the sweet spot where a lower rate, greater investment and the resulting production will combine to optimize the State's overall position for the future. However, that is a judgment call for you to make as the people's elected representatives. All we can promise is that, whatever you view as the optimal point, will yield effects in terms of investments being made here instead of somewhere else. You don't need promises about what individual companies might or might not do. Instead, you can count on those companies' shareholders to expect, and demand, that investment opportunities here that beat the competition will be pursued, instead of a less competitive alternative elsewhere.

bp

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

April 9, 2013

The Honorable Bill Stoltze, Co-chair
The Honorable Alan Austerman, Co-Chair
State of Alaska
House Finance Committee
State Capitol MS 3100
Juneau, AK 99801

Dear Representatives Stoltze and Austerman:

This letter responds to requests for additional information made during yesterday's House Finance Committee hearing which I was unable to provide at that time.

As requested by Representative Wilson we created a new slide reflecting the impact of the House Resources Committee Substitute for SB21 similar to our original slide (page 8) which reflected the ACES impact. Both are included here for ease of comparison.

In response to Representative Costello's question on costs, I referred to a back-up slide not at my disposal during my testimony. The attached page titled "Wood MacKenzie*- Sample 2013 Operating Costs", provides the requested information and demonstrates that, in addition to the high fiscal costs under ACES, oil operations are challenged by high operating costs.

Thank you again for the opportunity to testify before the House Finance Committee, and for the opportunity to provide this additional information.

Sincerely,

Damian Bilbao
Head of Finance
BP Exploration (Alaska) Inc.

DB/dms
Enclosures

Why doesn't ACES work?

Example at $110 per barrel

Alaska State Revenue $36

Federal Income Tax $12

Deductible Costs $40

$22 – less *non-deductible expenses

AK Cost of Supply Is >$88 / bbl

****** Source: DOR RSB Fall Forecast 2012, for FY 2013***

* *AS 43.55.165(e)*

HCS CSSB21(RES)

bp

Example at $110 per barrel

Alaska State Revenue $33

Federal Income Tax $13

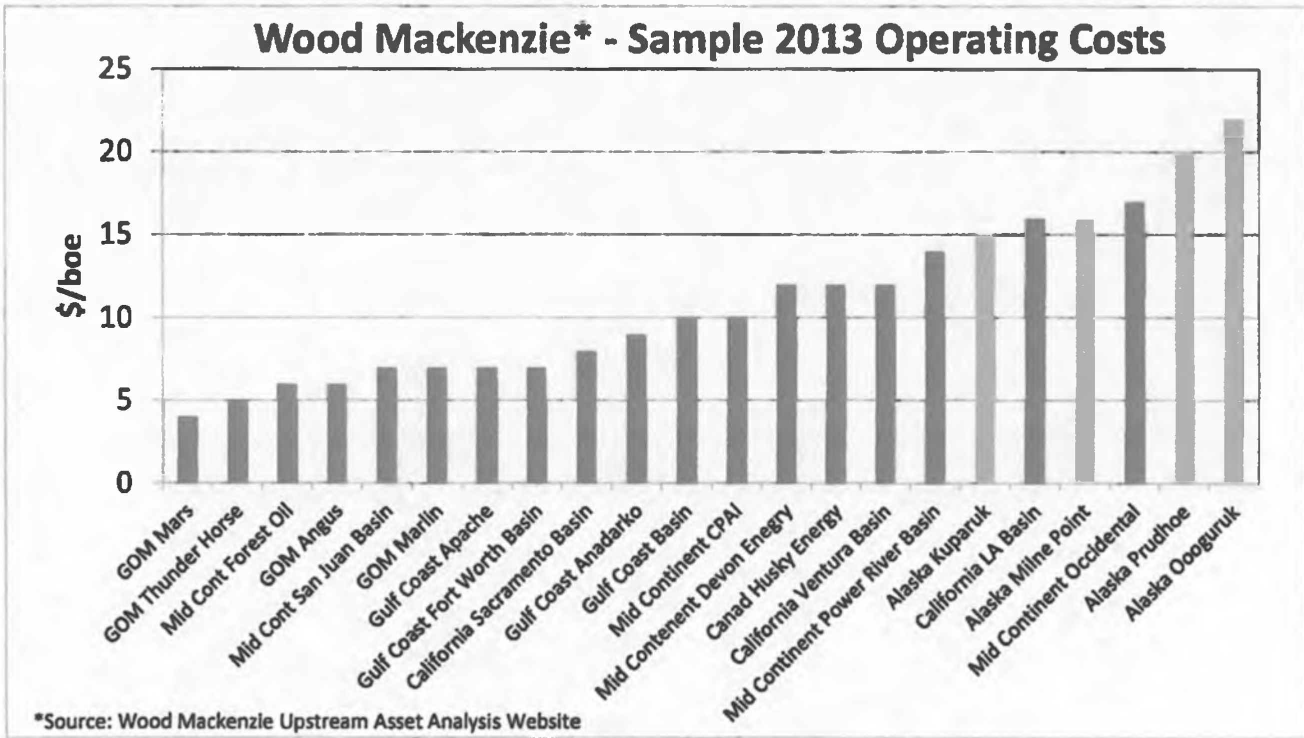
Deductible Costs $40

$24 – less *non-deductible expenses

AK Cost of Supply Is >$86 / bbl

****** Source: DOR RSB Fall Forecast 2012, for FY 2013***

* *AS 43.55.165(e)*


Wood Mackenzie* - Sample 2013 Operating Costs
$/boe
0
5
10
15
20
25
GOM Mars
GOM Thunder Horse
Mid Cont Forest Oil
GOM Angus
Mid Cont San Juan Basin
GOM Marlin
Gulf Coast Apache
Gulf Coast Fort Worth Basin
California Sacramento Basin
Gulf Coast Anadarko
Gulf Coast Basin
Mid Continent CPAI
Mid Contenent Devon Enegry
Canad Husky Energy
California Ventura Basin
Mid Continent Power River Basin
Alaska Kuparuk
California LA Basin
Alaska Milne Point
Mid Continent Occidental
Alaska Prudhoe
Alaska Ooguruk
*Source: Wood Mackenzie Upstream Asset Analysis Website

THE STATE of ALASKA
GOVERNOR SEAN PARNELL

Department of Revenue

COMMISSIONER'S OFFICE
Bryan Butcher, Commissioner

333 Willoughby Avenue, 11th Floor
PO Box 110400
Juneau, Alaska 99811-0400
Main: 907.465.2300
Fax: 907.465.2389

April 10, 2013

The Honorable Bill Stoltze
The Honorable Alan Austerman
Alaska State Representatives
Co-Chairs, House Finance Committee
State Capitol Rooms 515 and 505
Juneau, AK 99801

Dear Representatives Stoltze and Austerman:

The purpose of this letter is to provide you with a response to some of the questions that came up during the House Finance Committee meeting April 9, 2013. This includes follow-up questions during DOR testimony and a presentation about decline rates by EconOne. Additionally, we are including responses for additional questions that were provided to the department through the committee chair.

1. Provide fiscal impact of the current version of SB21, assuming a 3% production decline beginning in FY 2017.

Figure 1 and 2 at the end of this document present the summary fiscal analysis assuming the Spring 2013 forecast, at 33% and 35% base rates. We also include below that, a comparison of what the fiscal impact would be in each year assuming a 3% decline rate beginning in FY 2017.

2. Provide information about the number of wells drilled, in a recent year.

Attached please find a series of charts provided by AOGCC showing current and historical data for exploratory, development, and service wells. These and other useful charts are available through AOGCC's website at http://doa.alaska.gov/ogc/ActivityCharts/achtindex.html. Any detailed questions about these slides should be directed to AOGCC.

3. Provide EconOne slide 5 at $110, $120, and $130 real.

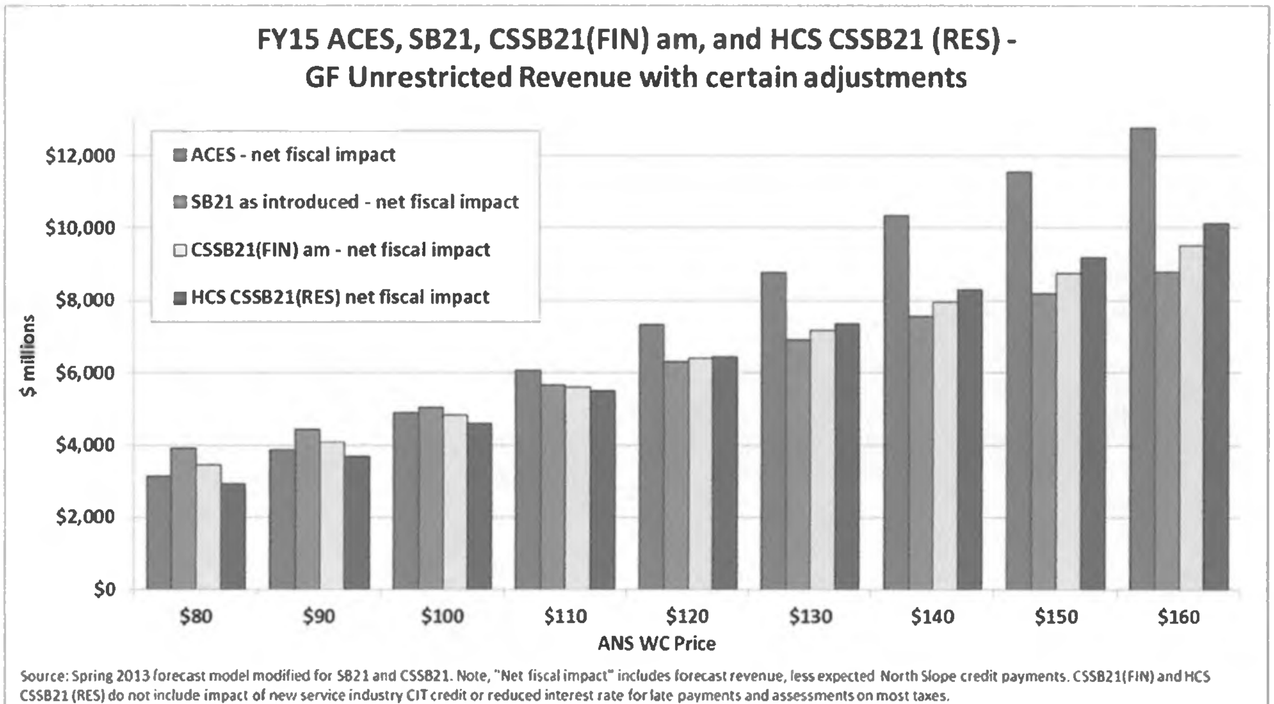
See attached EconOne slide deck that responds to this request.

4. Provide another copy of EconOne slides regarding activity in Alberta.

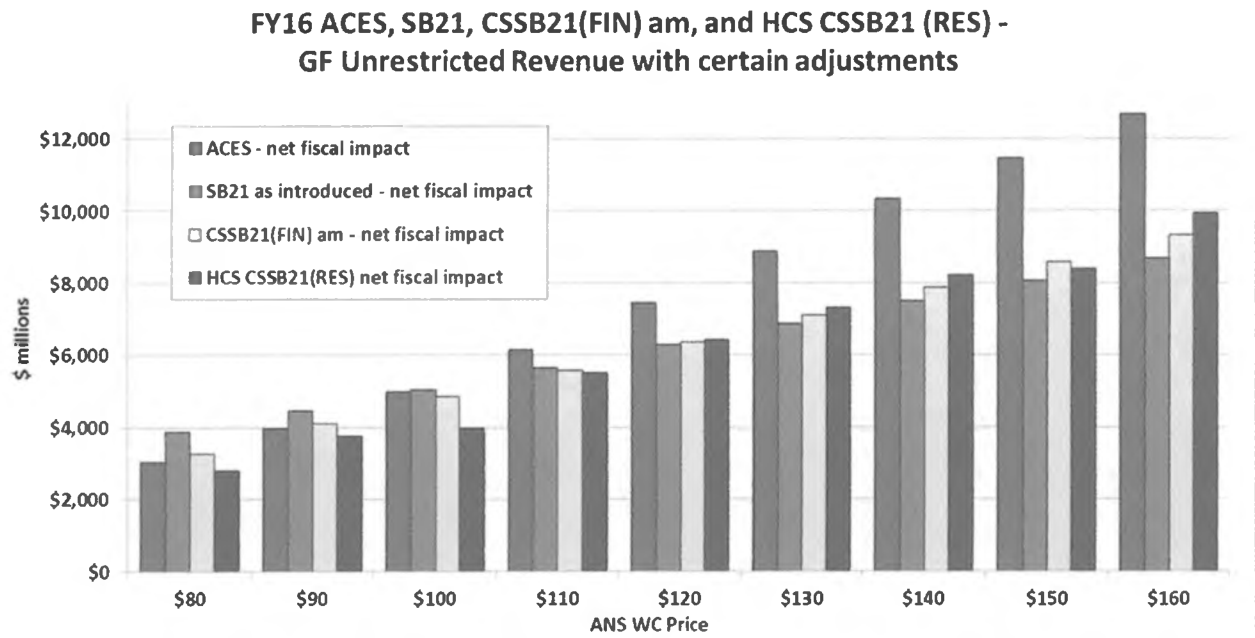
See attached EconOne slide deck that responds to this request.

5. We would like to see charts showing a comparison of the current bill, and the other committee version of SB 21 modeled by consultants – and compared to the revenue ACES would generate, with the decline curve the Department of Revenue uses in its latest forecast until 2016, and a 3% decline curve in production starting in 2017. Conoco predicts that 3% rate for the Legacy Fields starting in 2017 – and predicts newer fields will likely reduce that decline curve further. But we will just ask for a model that uses the 3% decline rate starting in 2017. We would like to see these charts for 2014 – 2020, and price ranges from \$80/barrel to \$160/barrel.

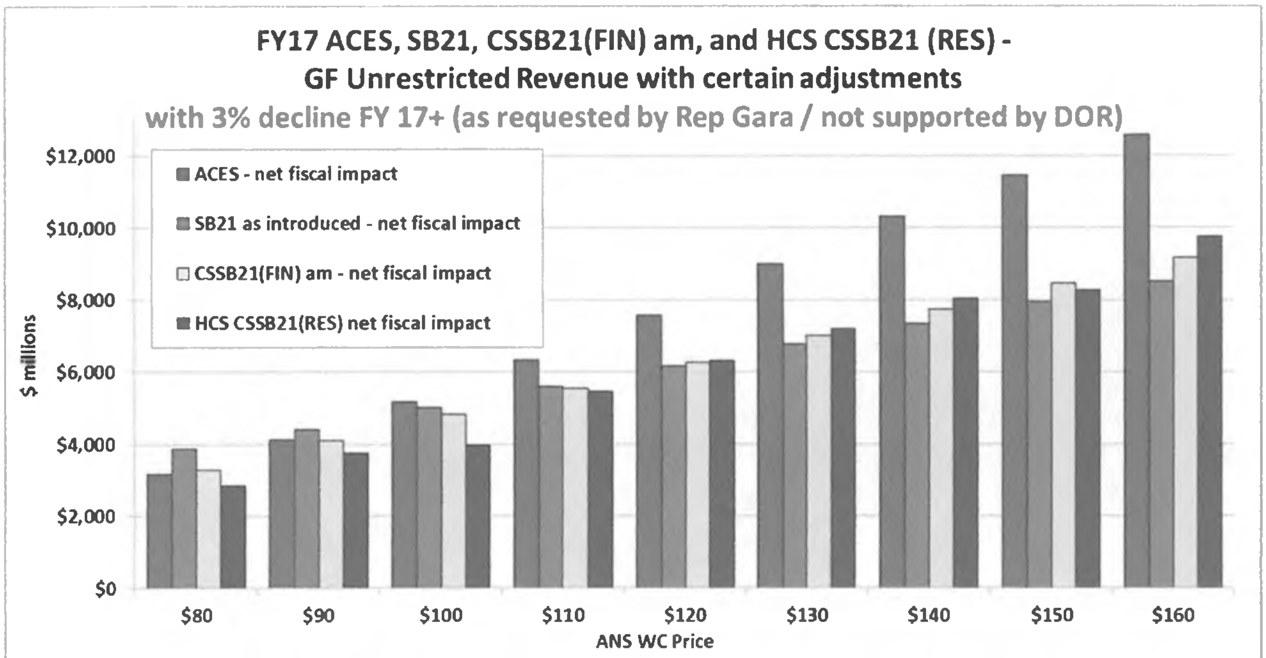
See following bar charts for FY 2015-FY 2019 comparing estimated General Fund Unrestricted Revenue under the three tax systems. For purposes of this request we include the net fiscal impact of each tax system, adjusting for refunded North Slope credits. For this analysis we have assumed a 3% production decline rate beginning in FY 2017. This decline rate is as requested by Representative Gara and DOR does not endorse or support this assumption. Note that we have included FY 2015-FY 2019 only. FY 2014 is not representative of the fiscal impact of proposed legislation as the effective date of the legislation is in the middle of the fiscal year. FY 2020 is beyond the scope of our fiscal note.



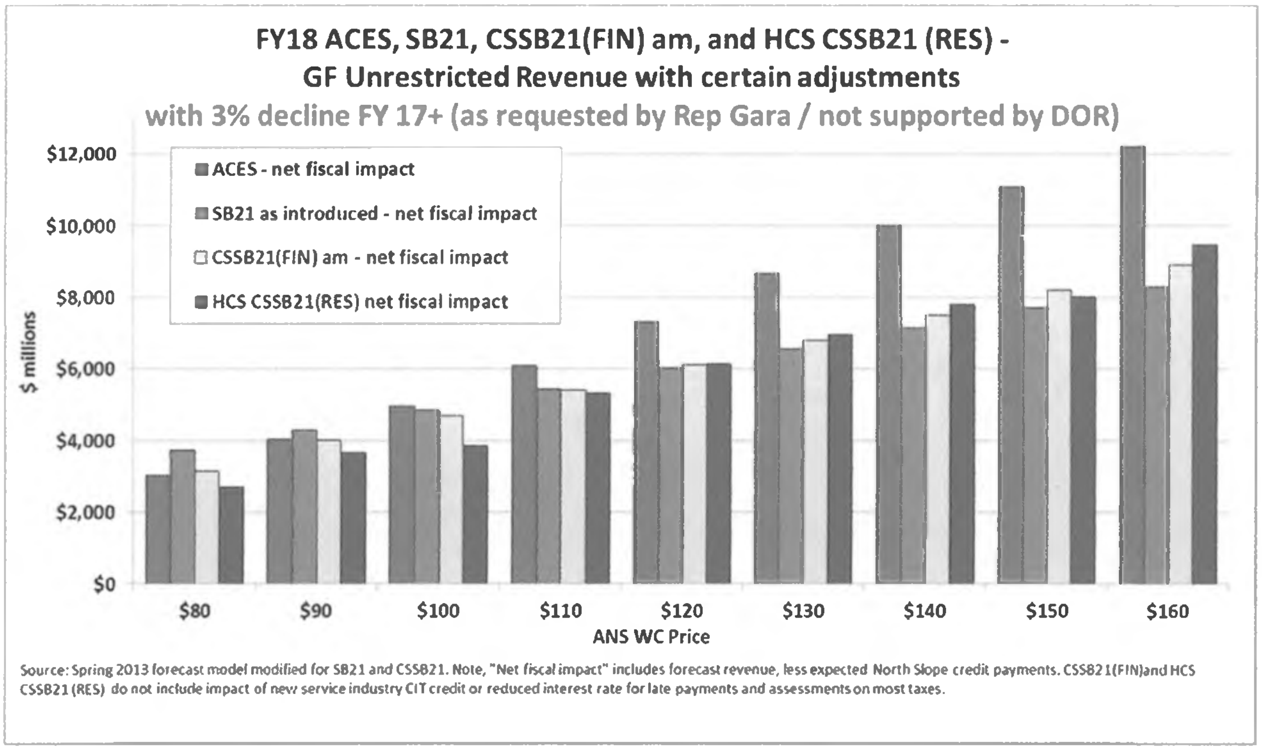
Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN) and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.

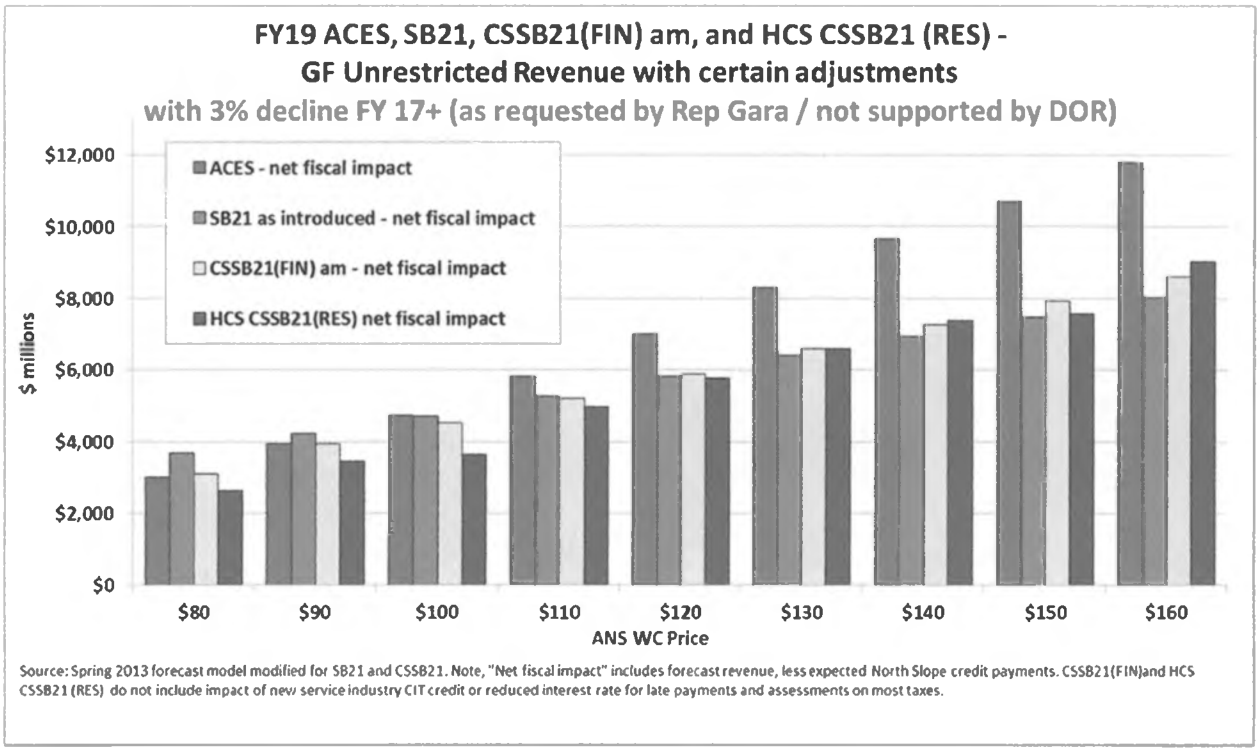


Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.



Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.


FY18 ACES, SB21, CSSB21(FIN) am, and HCS CSSB21 (RES) -
GF Unrestricted Revenue with certain adjustments
with 3% decline FY 17+ (as requested by Rep Gara / not supported by DOR)
ACES - net fiscal impact
SB21 as introduced - net fiscal impact
CSSB21(FIN) am - net fiscal impact
HCS CSSB21(RES) net fiscal impact
$ millions
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$0
$80
$90
$100
$110
$120
$130
$140
$150
$160
ANS WC Price
Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.


FY19 ACES, SB21, CSSB21(FIN) am, and HCS CSSB21 (RES) -
GF Unrestricted Revenue with certain adjustments
with 3% decline FY 17+ (as requested by Rep Gara / not supported by DOR)
ACES - net fiscal impact
SB21 as introduced - net fiscal impact
CSSB21(FIN) am - net fiscal impact
HCS CSSB21(RES) net fiscal impact
$ millions
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$0
$80
$90
$100
$110
$120
$130
$140
$150
$160
ANS WC Price
Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.

6. From EconOne's April 9 presentation, we would like the chart on page 6 to reflect the following scenarios:

a. The decline rate reflected in the DOR Spring 2013 Revenue Forecast;
b. and, starting in 2017, a 3% decline rate.
c. Also, produce these scenarios assuming prices between \$90 and \$140 per barrel.
d. Also, include a bar on the chart assuming the same decline rate under SB21 as under ACES.
e. Also, show how much new oil in annual barrels will be needed to make up for the loss of revenue by adopting the various versions of SB21 under these requested assumptions.

See attached slide deck from EconOne that responds to this request.

We hope that the answers set forth above have addressed your questions. Please do not hesitate to contact me if you have further questions.

Sincerely,

Bruce Tang

Bruce Tangeman
Deputy Commissioner

Attachments:
- Alberta Benchmark slides from EconOne
- Drilling and well charts from AOGCC
- Modified slides from EconOne April 9, 2013 presentation

Cc: House Finance Committee Members

Figure 1: Fiscal Impact Summary table, Spring 2013 Forecast Assumptions, 33% base rate

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Spring 2013 Forecast ($millions)[1]

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$725	-$1,400	-$1,725	-$1,875	-$1,650	-$1,525
2. Base tax rate changed to 33% of production tax value	$425	$825	$875	$875	$800	$750
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$675	$650	$525	$475	$450
4. Net operating loss credit rate increased to 33%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	$0	-$25	-$25	-$50	-$25	-$50
6. Provision requiring credits be taken over 2 years eliminated[2]	-$225					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8. Credit of $5 per taxable barrel / Sliding scale credit per taxable barrel based on oil price	-$425	-$825	-$775	-$750	-$700	-$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	$0	$0	$0	$0	$0	$0
12. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
13. 2016 required report to legislature	No fiscal impact					
14. Requirement to consider Joint Interest Billings in audit process	Indeterminate					
15. AIDEA bonding authority to finance oil and gas processing facilities	No Department of Revenue fiscal impact					
Total Revenue Impact	**-$650 to -$700**	**-$750 to -$800**	**-$1000 to -$1050**	**-$1300 to -$1350**	**-$1125 to -$1175**	**-$1100 to -$1150**
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits		-$30	-$30	-$30	-$30	-$30
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$800 to -$850**	**-$630 to -$680**	**-$880 to -$930**	**-$1180 to -$1230**	**-$1005 to -$1055**	**-$980 to -$1030**

Total Fiscal Impact with 3% decline rate in FY17-FY19 - does not include potential revenue impacts from potential increases in production[3] (3% decline rate as requested by Rep Gara / not supported by DOR)	**-$800 to -$850**	**-$630 to -$680**	**-$880 to -$930**	-$1205 to -$1255	-$1130 to -$1180	-$1130 to -$1180

[1]The impacts listed are based on production and prices as forecasted in our Spring 2013 revenue forecast. The forecasted oil prices are between $109.61 and $118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

[2]Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $375 million, with $225 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

[3]NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

Figure 2: Fiscal Impact Summary table, Spring 2013 Forecast Assumptions, 35% base rate

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Spring 2013 Forecast ($millions)[1]

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$725	-$1,400	-$1,725	-$1,875	-$1,650	-$1,525
2. Base tax rate changed to 35% of production tax value	$550	$1,050	$1,100	$1,100	$1,000	$925
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$675	$650	$525	$475	$450
4. Net operating loss credit rate increased to 33%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	$0	-$25	-$25	-$50	-$25	-$50
6. Provision requiring credits be taken over 2 years eliminated[2]	-$225					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8. Credit of $5 per taxable barrel / Sliding scale credit per taxable barrel based on oil price	-$425	-$825	-$775	-$750	-$700	-$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	$0	$0	$0	$0	$0	$0
12. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
13. 2016 required report to legislature	No fiscal impact					
14. Requirement to consider Joint Interest Billings in audit process	Indeterminate					
15. AIDEA bonding authority to finance oil and gas processing facilities	No Department of Revenue fiscal impact					
Total Revenue Impact	-$525 to -$575	-$525 to -$575	-$775 to -$825	-$1075 to -$1125	-$925 to -$975	-$925 to -$975
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits to 35%		-$40	-$40	-$40	-$40	-$40
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$675 to -$725**	**-$415 to -$465**	**-$665 to -$715**	**-$965 to -$1015**	**-$815 to -$865**	**-$815 to -$865**

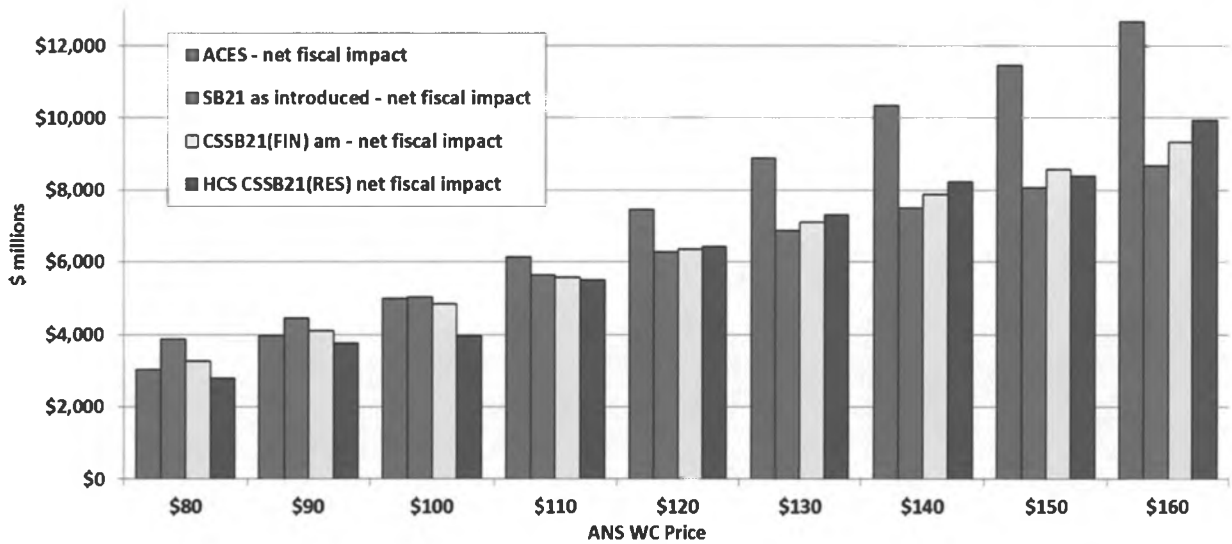
Total Fiscal Impact with 3% decline rate in FY17-FY19 - does not include potential revenue impacts from potential increases in production[3] (3% decline rate as requested by Rep Gara / not supported by DOR)	**-$675 to -$725**	**-$415 to -$465**	**-$665 to -$715**	-$990 to -$1040	-$915 to -$965	-$940 to -$990

[1]The impacts listed are based on production and prices as forecasted in our Spring 2013 revenue forecast. The forecasted oil prices are between $109.61 and $118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

[2]Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $375 million, with $225 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

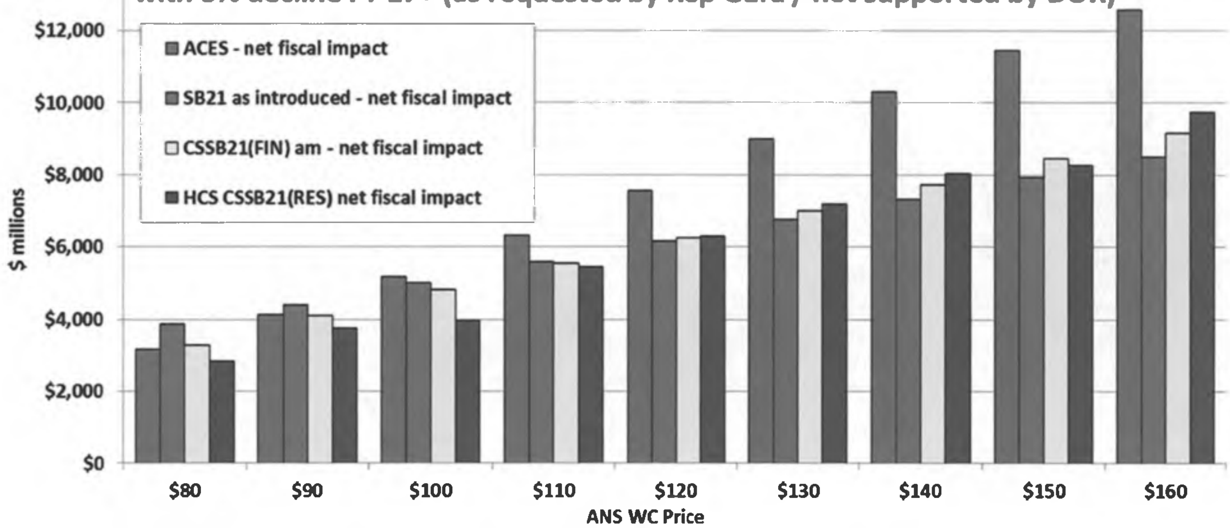
[3]NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

**FY16 ACES, SB21, CSSB21(FIN) am, and HCS CSSB21 (RES) -
GF Unrestricted Revenue with certain adjustments**



Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.

**FY17 ACES, SB21, CSSB21(FIN) am, and HCS CSSB21 (RES) -
GF Unrestricted Revenue with certain adjustments**
with 3% decline FY 17+ (as requested by Rep Gara / not supported by DOR)



Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.

Distributed by Rep. Gara
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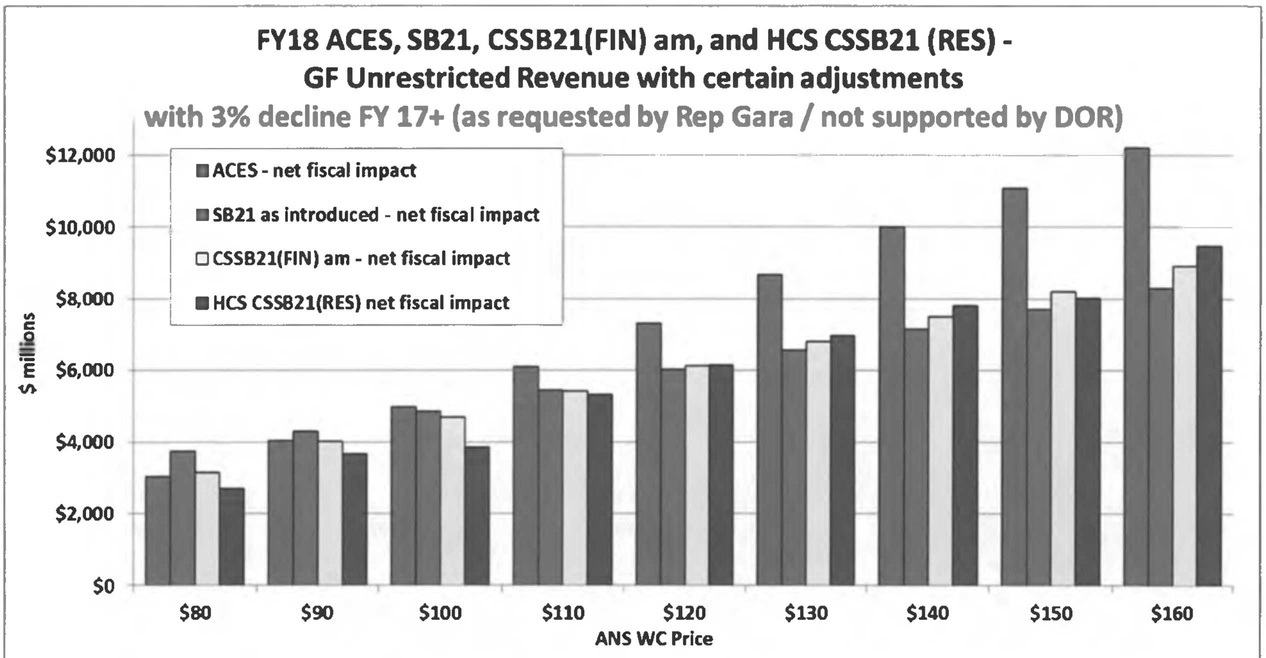
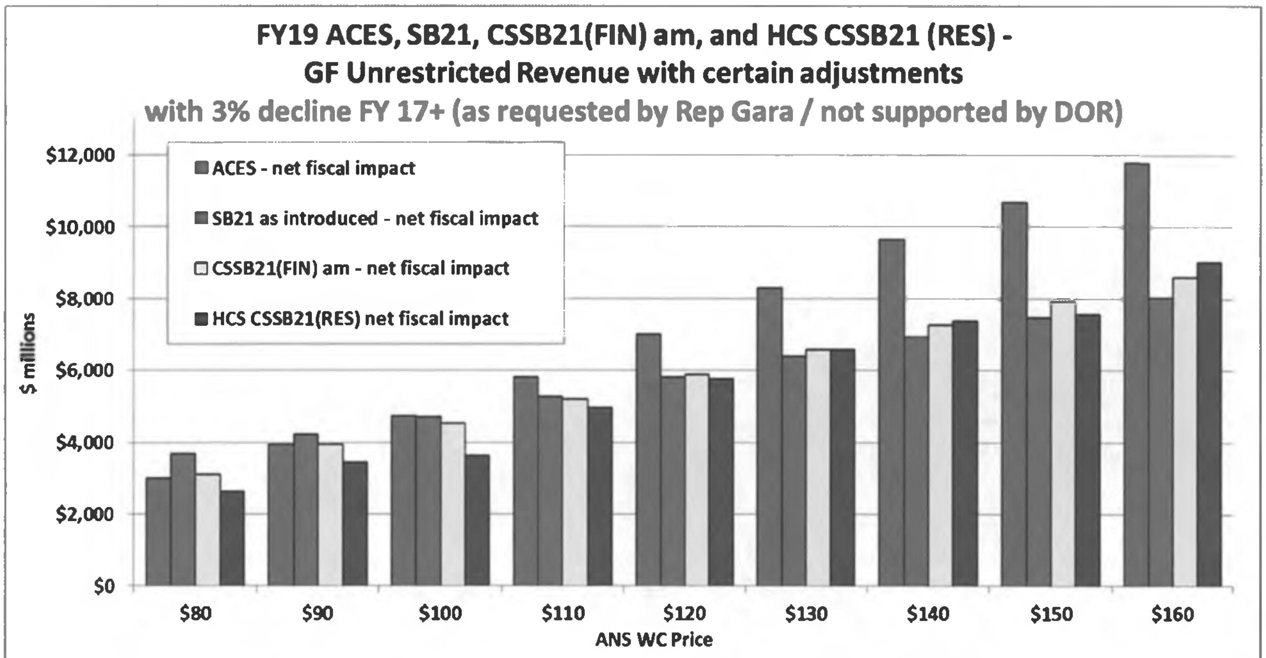


Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.



Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.

2

Vol. 18, No. 10 Week of March 10, 2013
Providing coverage of Alaska and northern Canada's oil and gas industry

Sending AK tech abroad

ConocoPhillips is using technology to increase production in Alaska, Outside

Eric Lidji

For Petroleum News

ConocoPhillips plans to spend some $2.5 billion in Alaska over the next five years using a collection of drilling technologies to mitigate declining production on the North Slope.

The largest producer in Alaska believes it can get some 35,000 barrels per day of incremental production from its three legacy North Slope oil fields by using 4-D seismic, coiled-tubing drilling and casing drilling to lower development costs and access additional resources, but as with any discussion of investments, the company insists it could do more if Alaska policymakers would make the fiscal regime more "competitive."

The 35,000 barrels per day would stem production declines in Alaska to some 3 percent per year by 2017, ConocoPhillips' Executive Vice President of Exploration and Production Matthew Fox said during the company's annual analyst day on Feb. 28. And, Fox noted, if ConocoPhillips brings the Alpine West/CD-5 satellite into production as scheduled in the 2015-16 timeframe, the annual decline could drop to some 2 percent.

The goal of the $2.5 billion program is to use newly perfected techniques to suck additional oil out of Prudhoe Bay, Kuparuk River and Alpine, but with tax changes "we can see additional opportunities that we could take advantage of to grow production in Alaska and to grow production through the Trans-Alaska Pipeline System," Fox said.

A pair of techniques

The program involves two techniques "honed" in Alaska.

The first brings down the cost of developing smaller oil pockets. In it, ConocoPhillips uses time-lapse 3-D seismic (or "4-D" seismic) to "illuminate pockets of oil that are in separate fault blocks or for whatever reason are not producing into an existing well bore," according to Executive Vice President of Technology and Projects Alan Hirshberg. "We could access these pockets using conventional drilling, but it's just not economic."

With a small tool at the end of coiled tubing equipment, ConocoPhillips can "twist and turn through the rock." This tool can turn more than 60 degrees over a 100-foot stretch of well, which "allows us to go right to these pockets that we found with the 4-D," he said.

Using this technique, ConocoPhillips recently drilled an "octolateral" well at the Kuparuk River unit. The well is a vertical hole with eight horizontal wells snaking out in different directions to target bypassed deposits. "We've actually found eight different zones near this well bore that we could go and hook up using coil-tubing drilling. … That's a very cost effective way to get at those zones that weren't producing before," Hirshberg said.

The second technique allows ConocoPhillips to access deposits once thought impossible to reach. Using "steerable drilling liners," the company can drill through unstable reservoirs or low-pressure formations to reach deeper targets. "Normally when you have these well bore instabilities, if you try to drill and then come back and run casing, you can't do it fast enough because the well bore collapses. So here, we're actually using the casing to drill," Hirshberg said. "And so the casings are already in place as we drill the hole. That gives us a mechanical method to be able to still access those resources.

Base development

It's unclear whether the investment is any different than normal fieldwork.

Earlier this year, ConocoPhillips said it planned to spend "about $1 billion" in Alaska in 2013, a slight increase over its 2012 budget meant to accommodate CD-5 development.

"When you look at the base development speed and pace in the legacy fields, it's the same (budget) as 2006," ConocoPhillips Alaska President Trond-Erik Johansen said.

Between 2005 and 2011, ConocoPhillips spent $733 million per year in Alaska, on average, with a low of $666 million in 2007 and a high of $1.4 billion in 2008. At $2.5 billion, the new five-year announced plan would break down to $500 million per year, in addition to other activities in the portfolio, such as CD-5 and Chukchi Sea exploration.

ConocoPhillips believes legacy fields are the "key" to stemming declines, but has said it cannot make the necessary investments under the existing tax system and it believes the proposed revision — in Senate Bill 21 and House Bill 72 — "does not contain sufficient investment incentives for legacy fields to offset Alaska's high cost environment."

Made in Alaska

Meanwhile, ConocoPhillips is exporting its Alaska technology Outside.

The $2.5 billion Alaska program is part of a larger effort by ConocoPhillips to increase production across its portfolio by some 600,000 barrels of oil equivalent per day by 2017.

"Of the growth that we're talking about, about half of it is going to come from oil production. … About 70 percent of that oil production comes from the Lower 48 and the rest of it is coming from Malaysia and projects in Europe," Chief Financial Officer Jeffrey Sheets said during the meeting. "And so where it's not coming from is places (where) we've had relatively higher tax rates, like Alaska."

House Finance Committee
Supplemental Slides as Requested By
Representative Gara

April 11, 2013

4/11 Presentation Slide 2
With per-barrel credits separated

Provisions in draft HCS CSSB21(FIN) and their Estimated Fiscal Impact as compared to Spring 2013 Forecast ($millions)[1]

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$725	-$1,400	-$1,725	-$1,875	-$1,650	-$1,525
2. Base tax rate changed to 35% of production tax value	$550	$1,050	$1,100	$1,100	$1,000	$925
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$675	$650	$525	$475	$450
4. Net operating loss credit rate increased to 45% until 1/1/16 then 35%; are transferable and refunda	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	$0	$0 to -$25	-$25 to -$50	-$25 to -$50	-$25 to -$50	-$50 to -$75
6. Provision requiring credits be taken over 2 years eliminated[2]	-$225					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8. Credit of $5 per taxable barrel	-$5	-$10	-$25	-$25	-$25	-$25
9. Sliding scale $0-$8 credit per taxable barrel based on oil price	-$420	-$815	-$750	-$725	-$675	-$650
10. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
11. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
12. Removal of 3-mile requirement for frontier basin tax credit	$0	$0	$0	$0	$0	$0
13. 2016 required report to legislature	No fiscal impact					
14. Establishes competitiveness review board	No fiscal impact					
Total Revenue Impact	**-$520 to -$570**	**-$490 to -$565**	**-$750 to -$825**	**-$1000 to -$1075**	**-$875 to -$950**	**-$850 to -$925**
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits to 45% until 1/1/16 then 35%		-$80	-$80	-$40	-$40	-$40
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$670 to -$720**	**-$420 to -$495**	**-$680 to -$755**	**-$890 to -$965**	**-$765 to -$840**	**-$740 to -$815**

[1]The impacts listed are based on production and prices as forecasted in our Spring 2013 revenue forecast. The forecasted oil prices are between $109.61 and $118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

[2]Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $375 million, with $225 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

[3]NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

4-7 Question #6, page 2

Estimated Fiscal Impact of different per-barrel credit levels under Fall 2012 Forecast ($millions)

Amount of credit	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$1 per taxable barrel credit	-$75	-$175	-$150	-$150	-$150	-$125
$2 per taxable barrel credit	-$175	-$325	-$325	-$300	-$275	-$275
$3 per taxable barrel credit	-$250	-$500	-$475	-$450	-$425	-$400
$4 per taxable barrel credit	-$350	-$650	-$625	-$600	-$550	-$525
$5 per taxable barrel credit	-$425	-$825	-$775	-$750	-$700	-$675
$6 per taxable barrel credit	-$525	-$1,000	-$950	-$900	-$825	-$800
$7 per taxable barrel credit	-$600	-$1,150	-$1,100	-$1,050	-$975	-$925
$8 per taxable barrel credit	-$700	-$1,325	-$1,250	-$1,200	-$1,100	-$1,075
$9 per taxable barrel credit	-$775	-$1,475	-$1,425	-$1,350	-$1,250	-$1,200
$10 per taxable barrel credit	-$850	-$1,650	-$1,575	-$1,500	-$1,400	-$1,325

4/7 Figure 1, Page 4

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Spring 2013 Forecast ($millions)[1]

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$725	-$1,400	-$1,725	-$1,875	-$1,650	-$1,525
2. Base tax rate changed to 33% of production tax value	$425	$825	$875	$875	$800	$750
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$675	$650	$525	$475	$450
4. Net operating loss credit rate increased to 33%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	$0	-$25	-$25	-$50	-$25	-$50
6. Provision requiring credits be taken over 2 years eliminated[2]	-$225					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8. Credit of $5 per taxable barrel / Sliding scale credit per taxable barrel based on oil price	-$425	-$825	-$775	-$750	-$700	-$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	$0	$0	$0	$0	$0	$0
12. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
13. 2016 required report to legislature	No fiscal impact					
14. Requirement to consider Joint Interest Billings in audit process	Indeterminate					
15. AIDEA bonding authority to finance oil and gas processing facilities	No Department of Revenue fiscal impact					
Total Revenue Impact	**-$650 to -$700**	**-$750 to -$800**	**-$1000 to -$1050**	**-$1275 to -$1325**	**-$1100 to -$1150**	**-$1050 to -$1100**
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits		-$30	-$30	-$30	-$30	-$30
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$800 to -$850**	**-$630 to -$680**	**-$880 to -$930**	**-$1155 to -$1205**	**-$980 to -$1030**	**-$930 to -$980**

[1]The impacts listed are based on production and prices as forecasted in our Spring 2013 revenue forecast. The forecasted oil prices are between $109.61 and $118.29.
All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

[2]Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $400 million, with $250 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

[3]NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

4/7 Figure 2, Page 5

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Fall 2012 Forecast ($millions)[1]

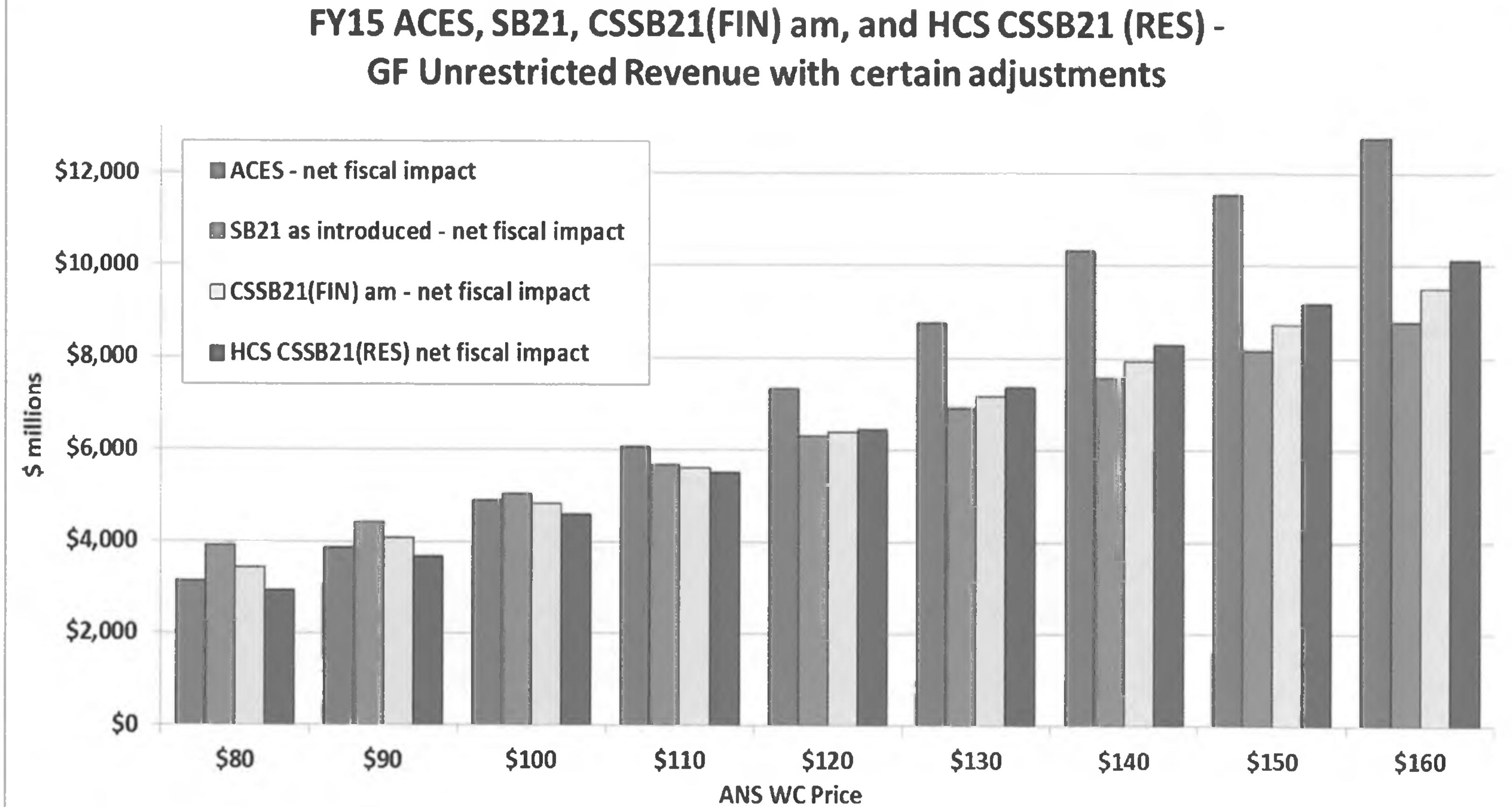
Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$800	-$1,500	-$1,700	-$1,800	-$1,750	-$1,650
2. Base tax rate changed to 35% of production tax value	$550	$1,075	$1,100	$1,075	$1,025	$975
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$700	$650	$550	$475	$400
4. Net operating loss credit rate increased to 33%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	$0	-$25	-$25	-$50	-$25	-$50
6. Provision requiring credits be taken over 2 years eliminated[2]	-$250					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8a. Credit of $5 per taxable barrel for GRE-eligible production	-$5	-$10	-$25	-$25	-$25	-$25
8b. Sliding scale credit per taxable barrel based on oil price for non GRE-eligible production	-$420	-$815	-$750	-$725	-$675	-$650
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	$0	$0	$0	$0	$0	$0
12. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
13. 2016 required report to legislature	No fiscal impact					
14. Requirement to consider Joint Interest Billings in audit process	Indeterminate					
15. AIDEA bonding authority to finance oil and gas processing facilities	No Department of Revenue fiscal impact					
Total Revenue Impact	**-$625 to -$675**	**-$575 to -$625**	**-$750 to -$800**	**-$975 to -$1025**	**-$975 to -$1025**	**-$1000 to -$1050**
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits to 35%		-$40	-$40	-$40	-$40	-$40
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$775 to -$825**	**-$465 to -$515**	**-$640 to -$690**	**-$865 to -$915**	**-$865 to -$915**	**-$890 to -$940**

[1]The impacts listed are based on production and prices as forecasted in our Fall 2012 revenue forecast. The forecasted oil prices are between $109.61 and $118.29.
All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

[2]Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $400 million, with $250 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

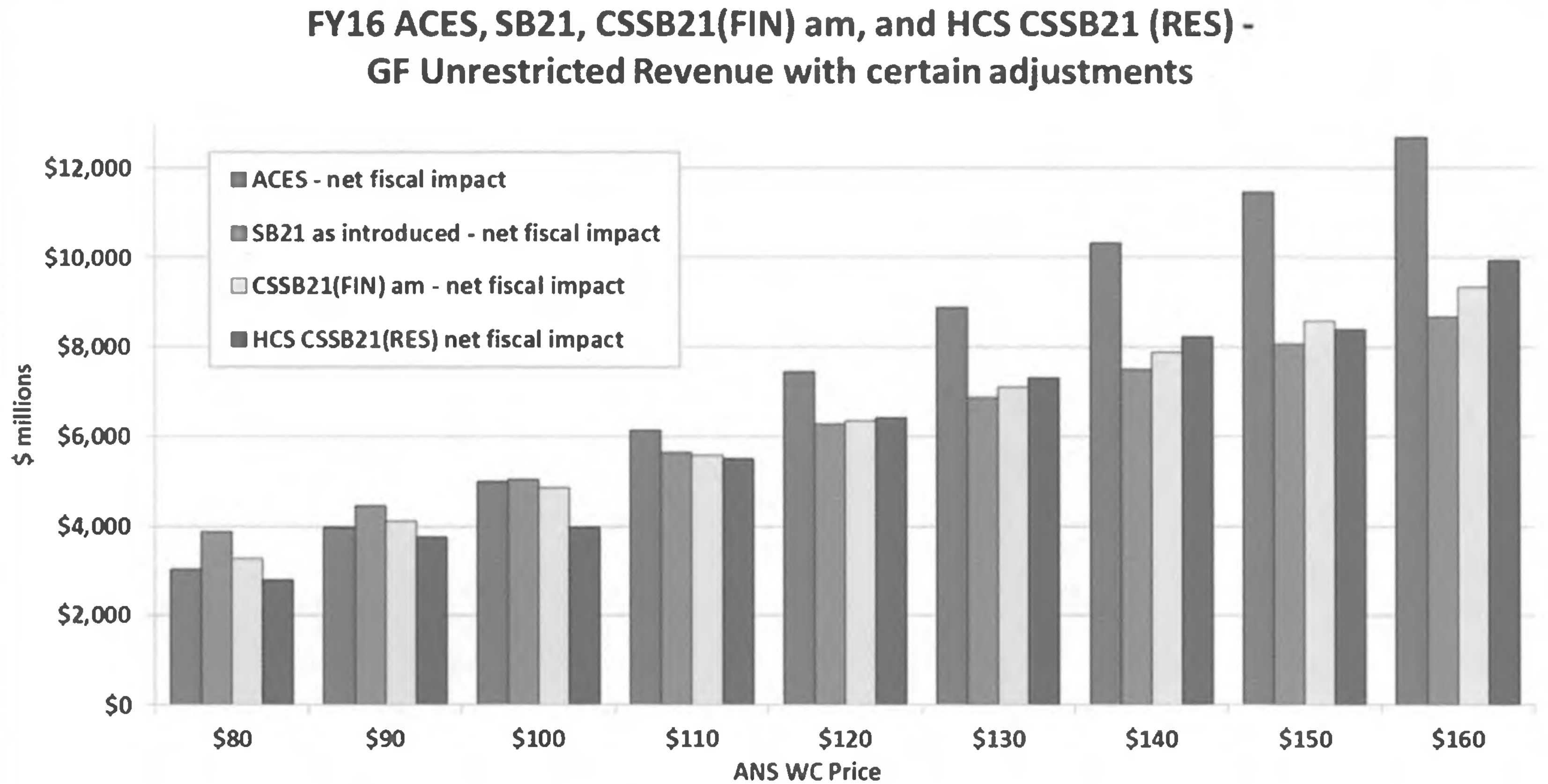
[3]NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

4/10 Revenue sensitivity – FY15



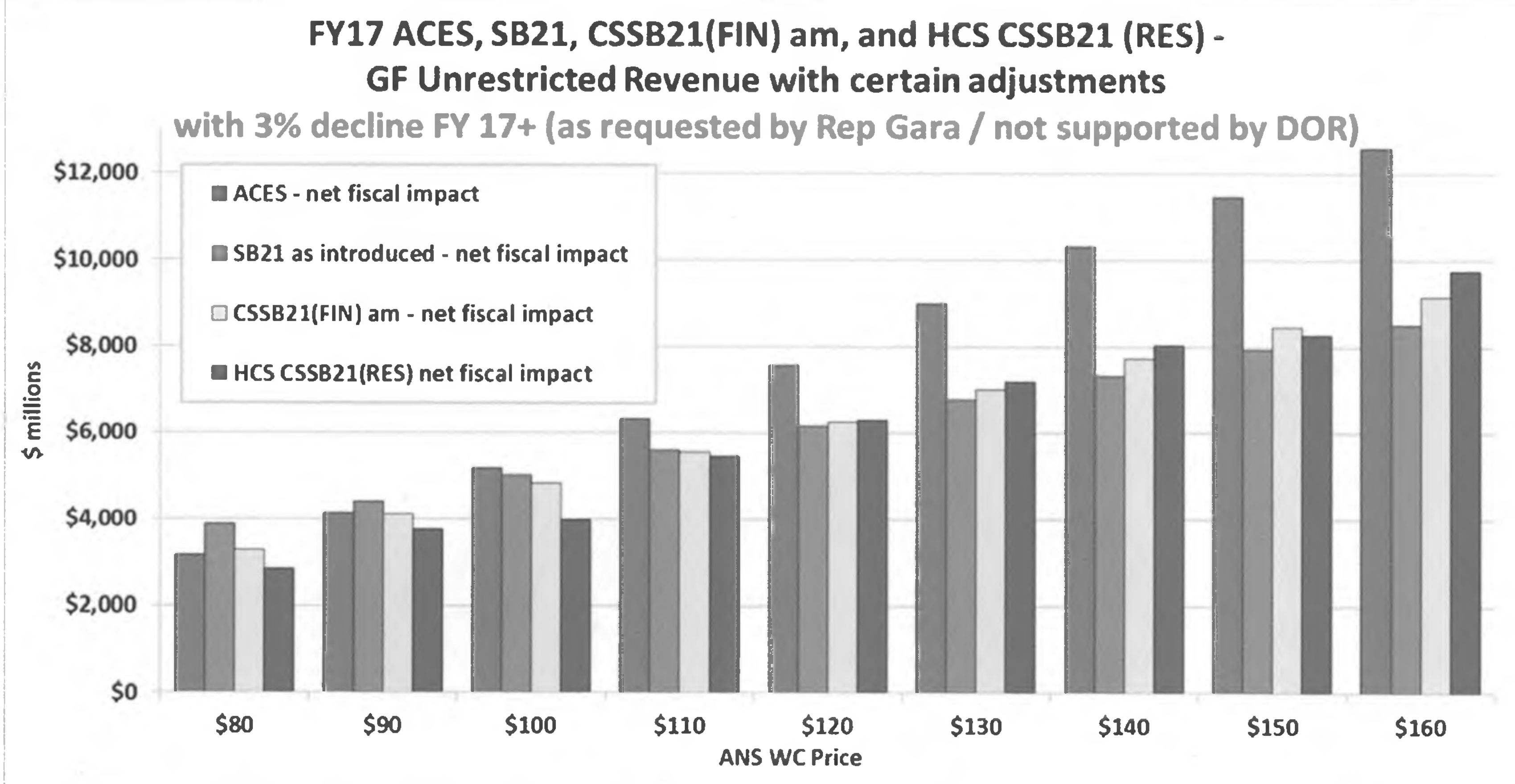
Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN) and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.

4/10 Revenue sensitivity – FY16



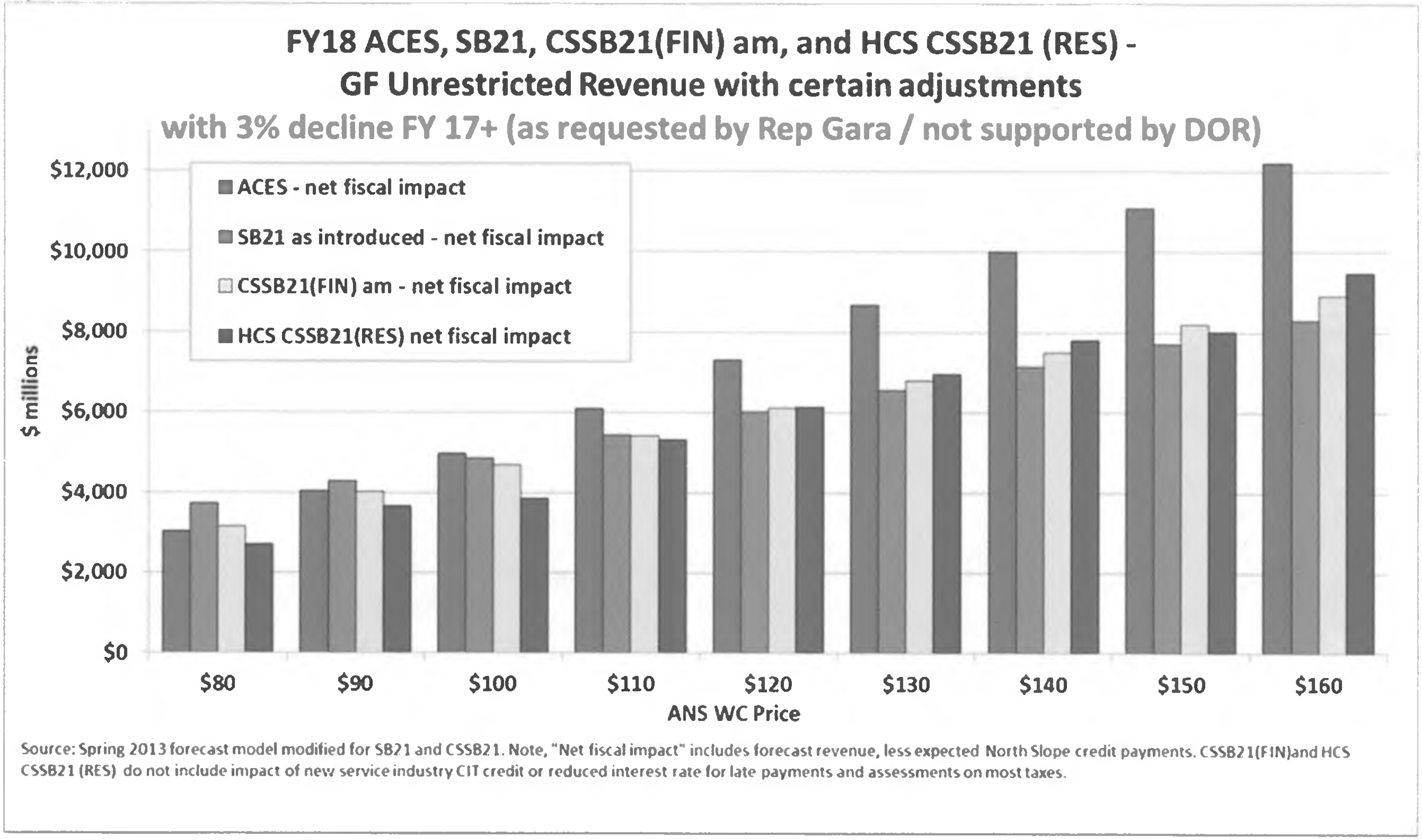
Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.

4/10 Revenue sensitivity – FY17 w 3% decline FY17+

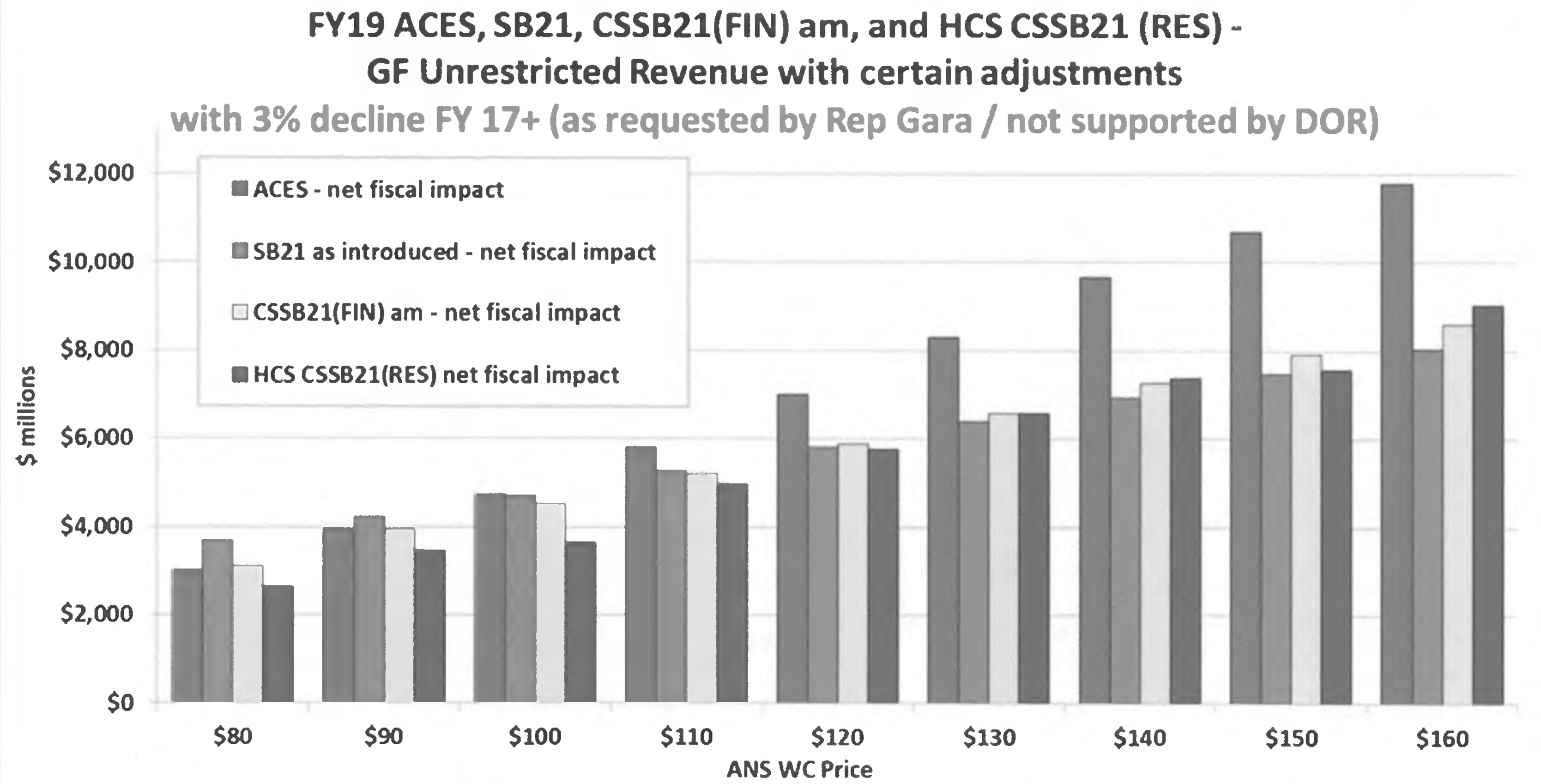


Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.

4/10 Revenue sensitivity – FY18 w 3% decline FY17+



4/10 Revenue sensitivity – FY19 w 3% decline FY17+



Source: Spring 2013 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. CSSB21(FIN)and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.

4/10 Page 6: Fiscal Impact Summary table, Spring 2013 Forecast Assumptions, 33% base rate

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Spring 2013 Forecast ($millions)[1]

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$725	-$1,400	-$1,725	-$1,875	-$1,650	-$1,525
2. Base tax rate changed to 33% of production tax value	$425	$825	$875	$875	$800	$750
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$675	$650	$525	$475	$450
4. Net operating loss credit rate increased to 33%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	$0	-$25	-$25	-$50	-$25	-$50
6. Provision requiring credits be taken over 2 years eliminated[2]	-$225					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8. Credit of $5 per taxable barrel / Sliding scale credit per taxable barrel based on oil price	-$425	-$825	-$775	-$750	-$700	-$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	$0	$0	$0	$0	$0	$0
12. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
13. 2016 required report to legislature	No fiscal impact					
14. Requirement to consider Joint Interest Billings in audit process	Indeterminate					
15. AIDEA bonding authority to finance oil and gas processing facilities	No Department of Revenue fiscal impact					
Total Revenue Impact	**-$650 to -$700**	**-$750 to -$800**	**-$1000 to -$1050**	**-$1300 to -$1350**	**-$1125 to -$1175**	**-$1100 to -$1150**
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits		-$30	-$30	-$30	-$30	-$30
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$800 to -$850**	**-$630 to -$680**	**-$880 to -$930**	**-$1180 to -$1230**	**-$1005 to -$1055**	**-$980 to -$1030**

Total Fiscal Impact with 3% decline rate in FY17-FY19 - does not include potential revenue impacts from potential increases in production[3] **(3% decline rate as requested by Rep Gara / not supported by DOR)**	**-$800 to -$850**	**-$630 to -$680**	**-$880 to -$930**	**-$1205 to -$1255**	**-$1130 to -$1180**	**-$1130 to -$1180**

[1]The impacts listed are based on production and prices as forecasted in our Spring 2013 revenue forecast. The forecasted oil prices are between $109.61 and $118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

[2]Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $375 million, with $225 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

[3]NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

4/10 Page 7: Fiscal Impact Summary table, Spring 2013 Forecast Assumptions, 35% base rate

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Spring 2013 Forecast ($millions)[1]

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$725	-$1,400	-$1,725	-$1,875	-$1,650	-$1,525
2. Base tax rate changed to 35% of production tax value	$550	$1,050	$1,100	$1,100	$1,000	$925
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$675	$650	$525	$475	$450
4. Net operating loss credit rate increased to 33%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	$0	-$25	-$25	-$50	-$25	-$50
6. Provision requiring credits be taken over 2 years eliminated[2]	-$225					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8. Credit of $5 per taxable barrel / Sliding scale credit per taxable barrel based on oil price	-$425	-$825	-$775	-$750	-$700	-$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	$0	$0	$0	$0	$0	$0
12. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
13. 2016 required report to legislature	No fiscal impact					
14. Requirement to consider Joint Interest Billings in audit process	Indeterminate					
15. AIDEA bonding authority to finance oil and gas processing facilities	No Department of Revenue fiscal impact					
Total Revenue Impact	-$525 to -$575	-$525 to -$575	-$775 to -$825	-$1075 to -$1125	-$925 to -$975	-$925 to -$975
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits to 35%		-$40	-$40	-$40	-$40	-$40
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$675 to -$725**	**-$415 to -$465**	**-$665 to -$715**	**-$965 to -$1015**	**-$815 to -$865**	**-$815 to -$865**

Total Fiscal Impact with 3% decline rate in FY17-FY19 - does not include potential revenue impacts from potential increases in production[3] (3% decline rate as requested by Rep Gara / not supported by DOR)	**-$675 to -$725**	**-$415 to -$465**	**-$665 to -$715**	-$990 to -$1040	-$915 to -$965	-$940 to -$990

[1] The impacts listed are based on production and prices as forecasted in our Spring 2013 revenue forecast. The forecasted oil prices are between $109.61 and $118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

[2] Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $375 million, with $225 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

[3] NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

*Corrected graphs

Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (RES) $90 West Coast ANS ($2012)

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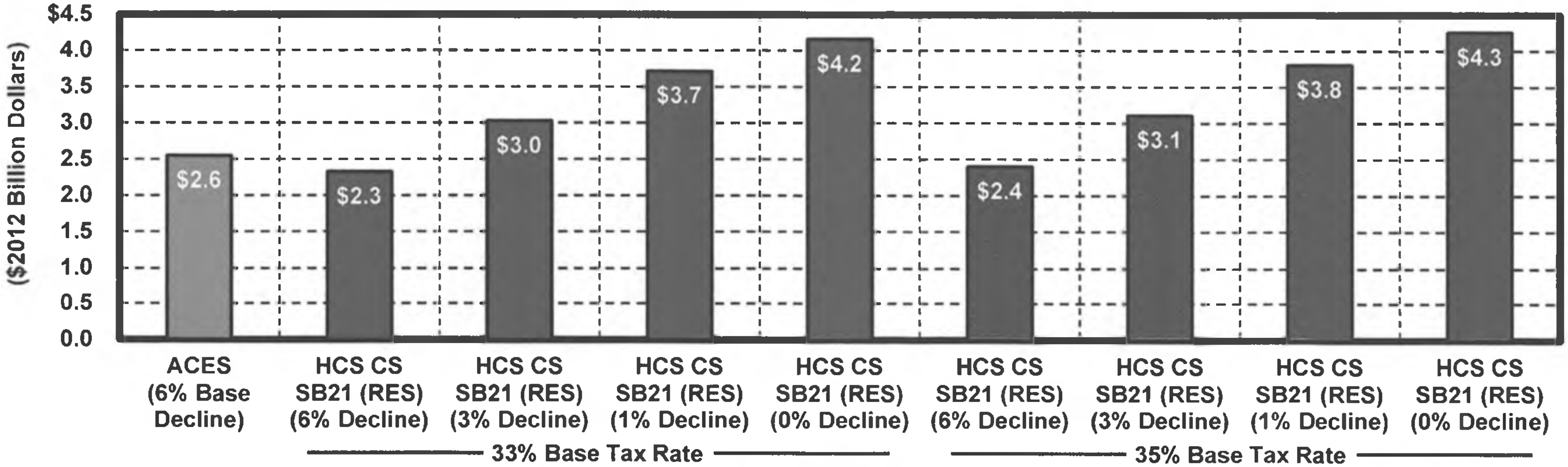
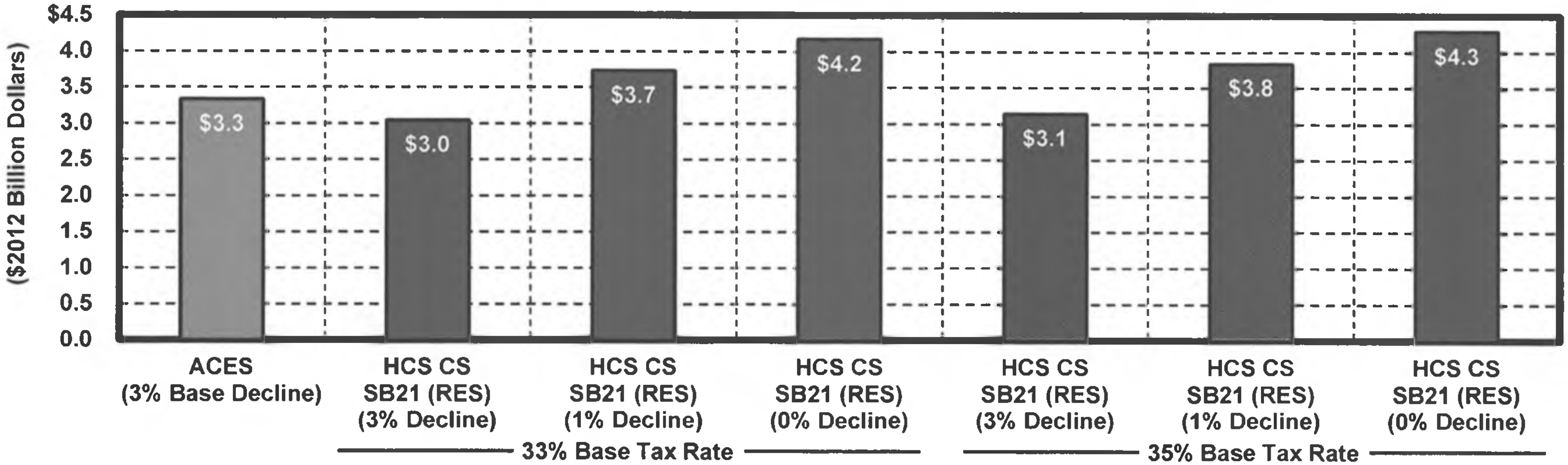
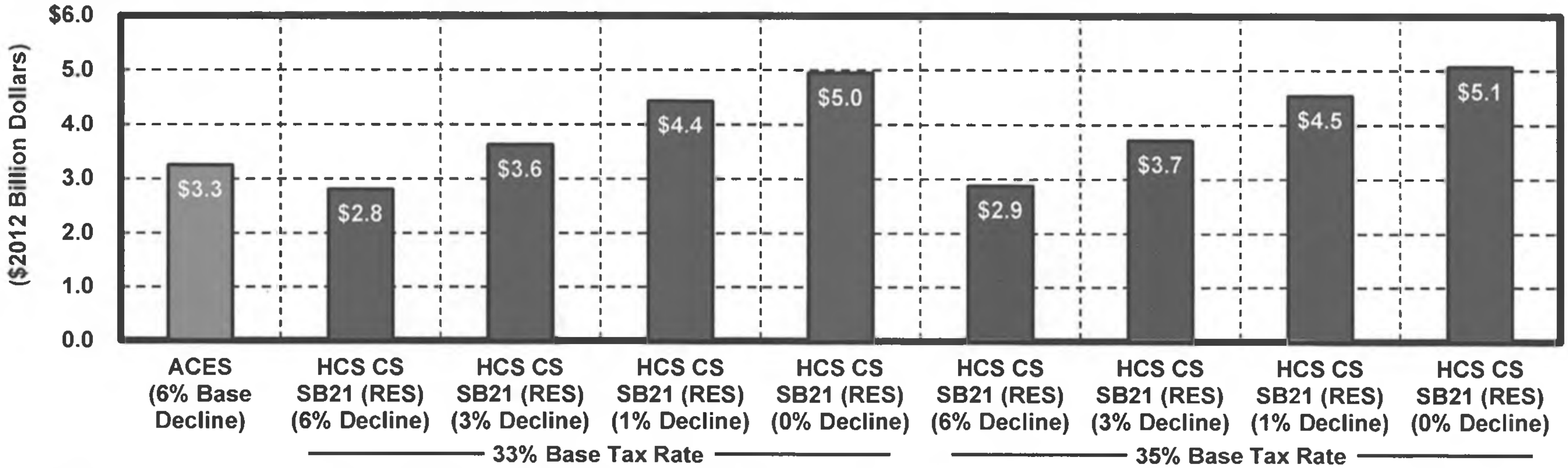
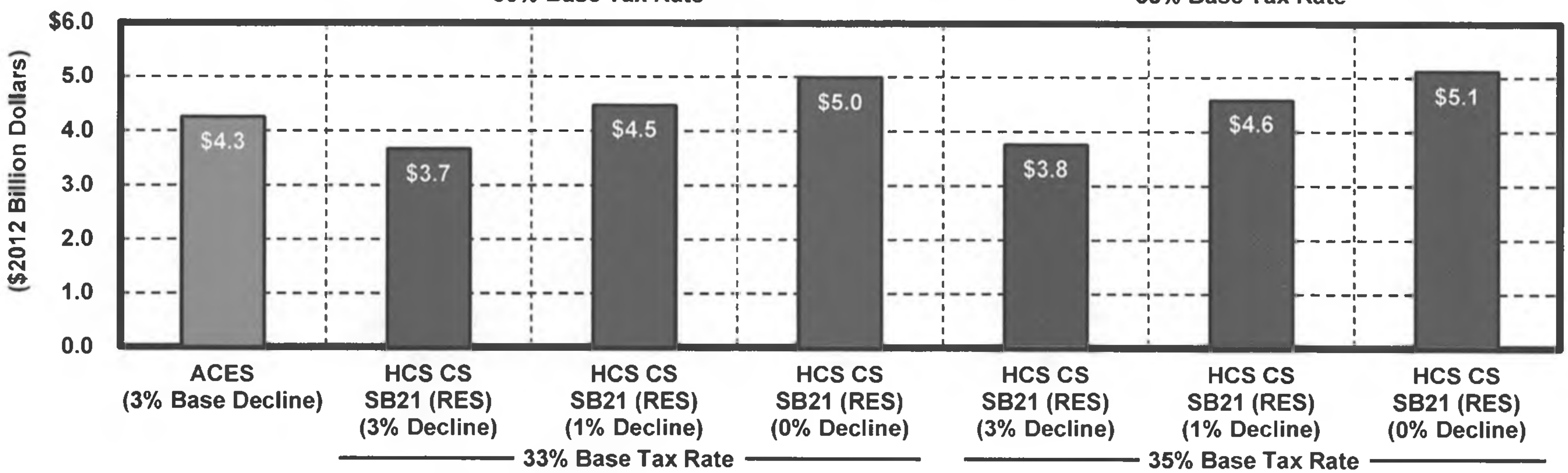




Note: All volumes over base assumed to qualify for GRE and carry 1/6th royalty.

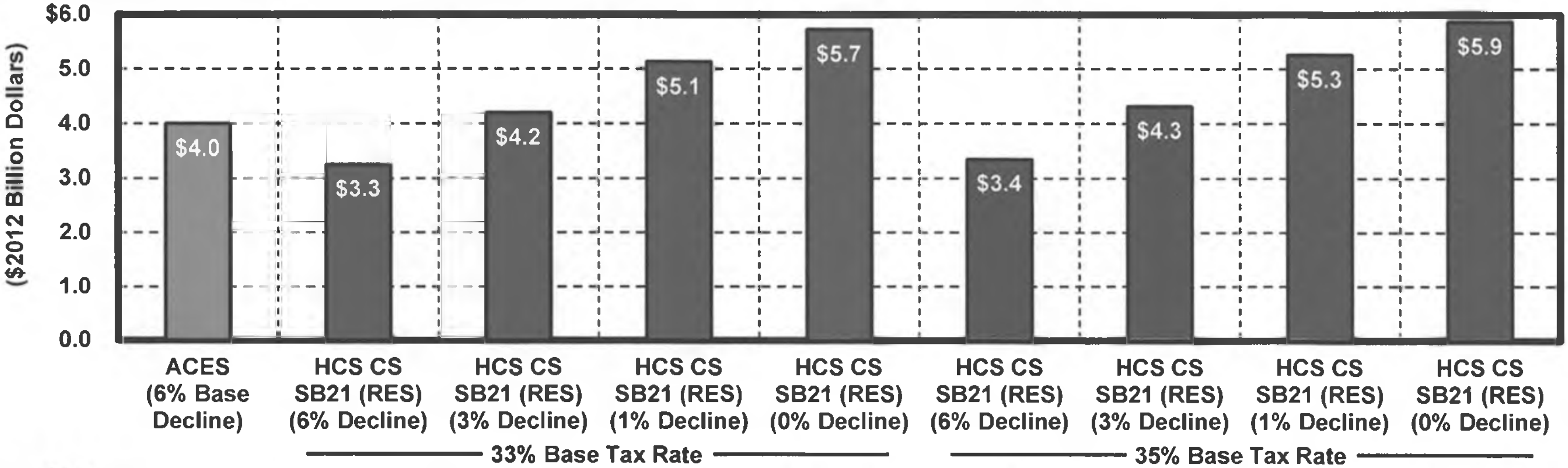
Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (RES) $100 West Coast ANS ($2012)

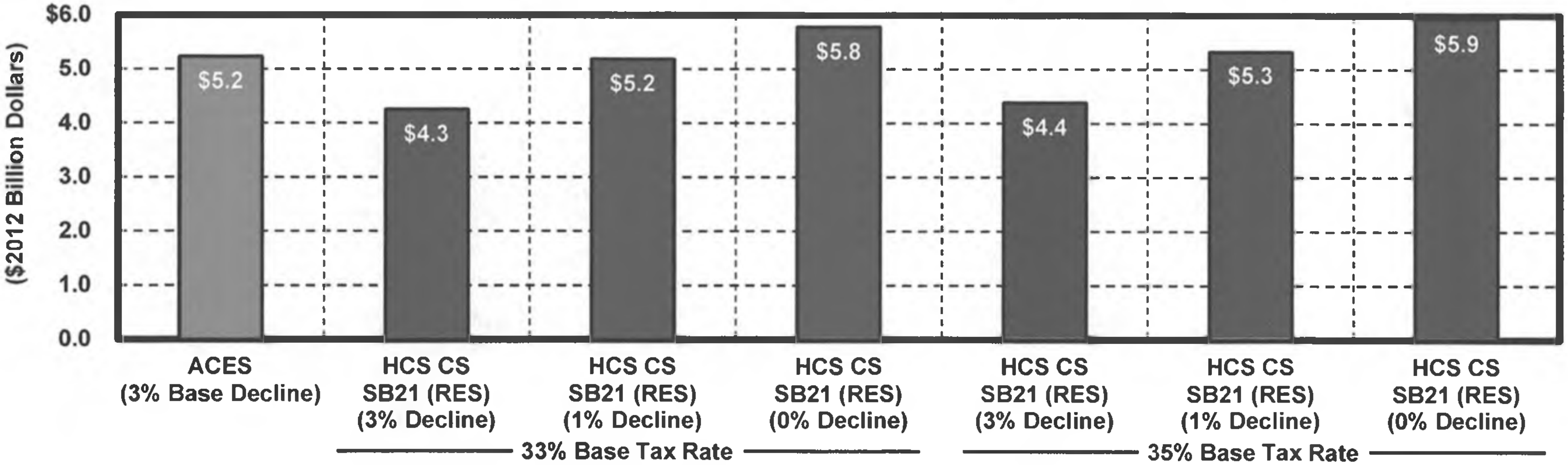




Note: All volumes over base assumed to qualify for GRE and carry 1/6th royalty.

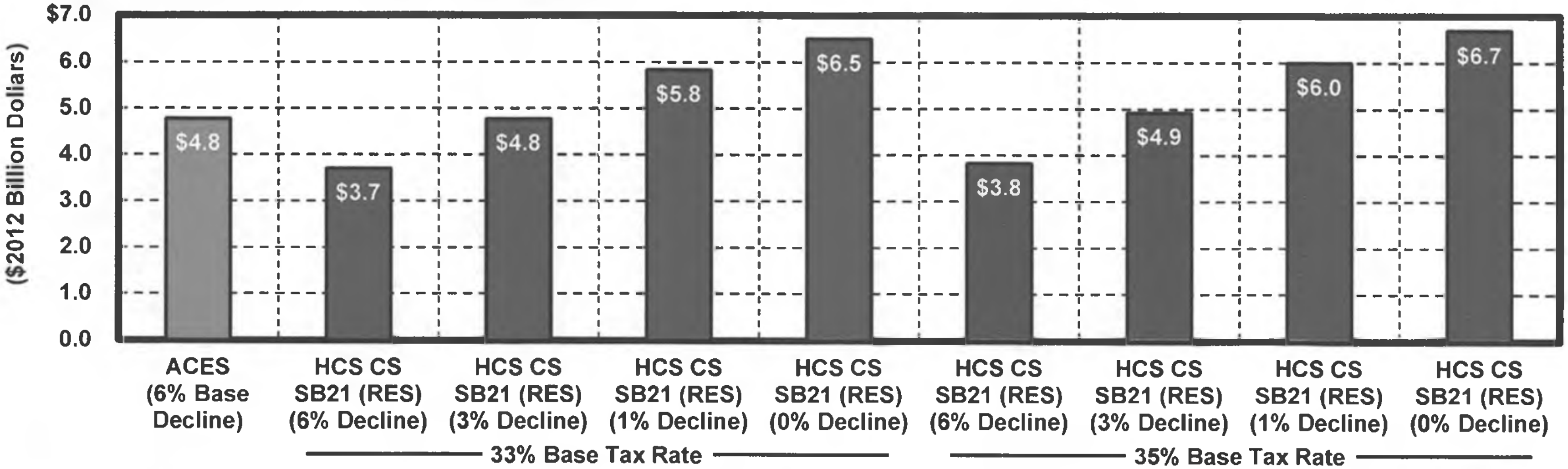
Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (RES) $110 West Coast ANS ($2012)

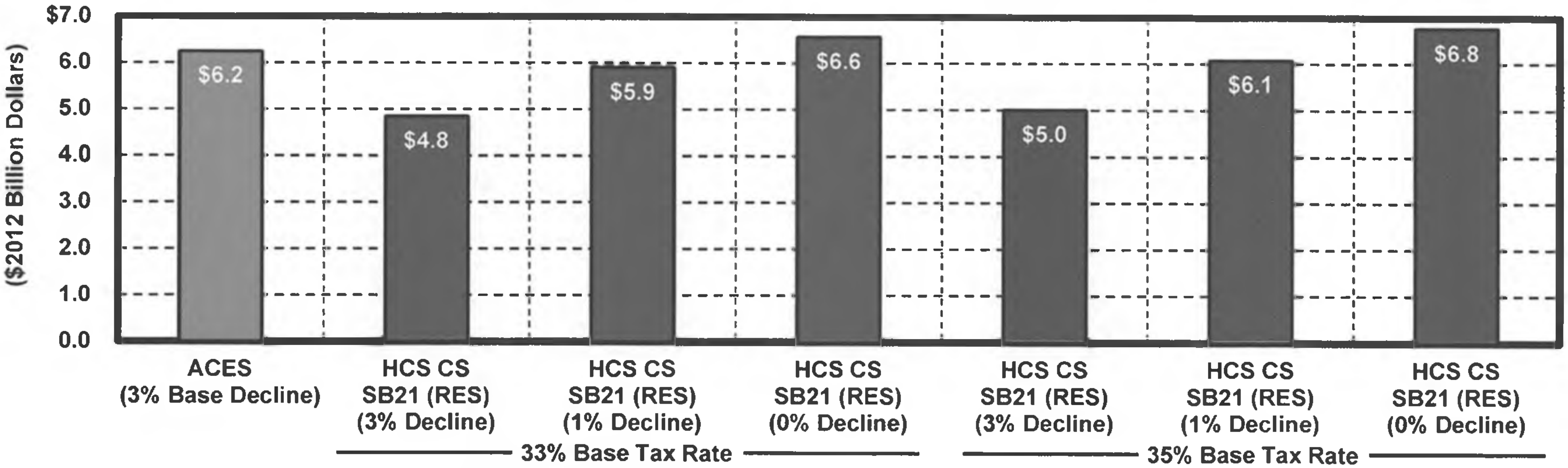




Note: All volumes over base assumed to qualify for GRE and carry 1/6th royalty.

Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (RES) $120 West Coast ANS ($2012)

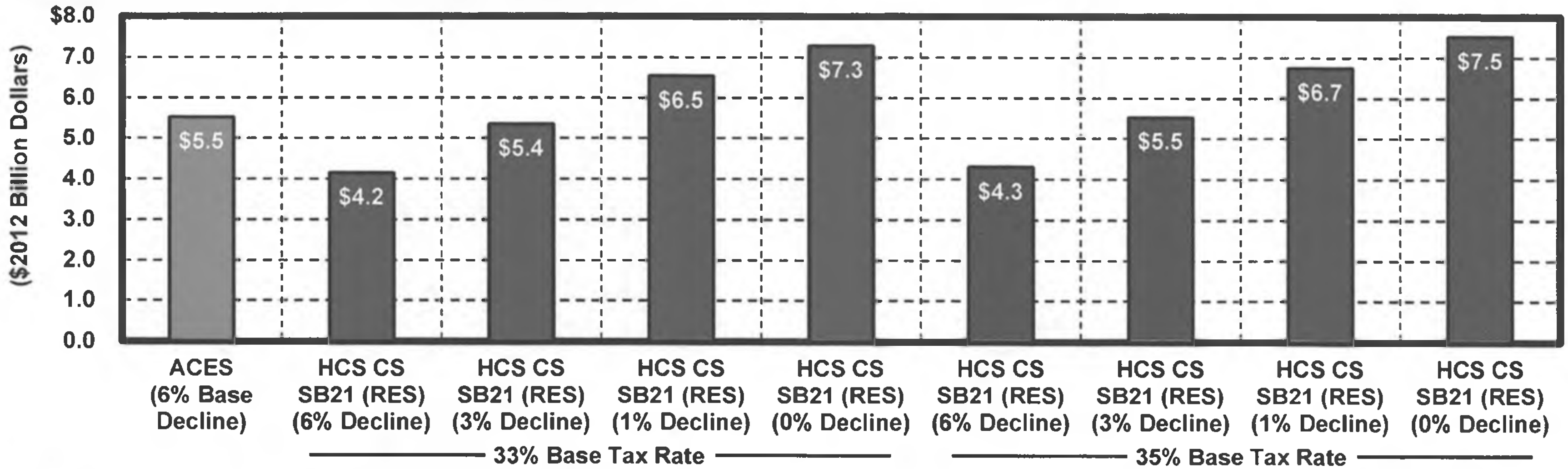


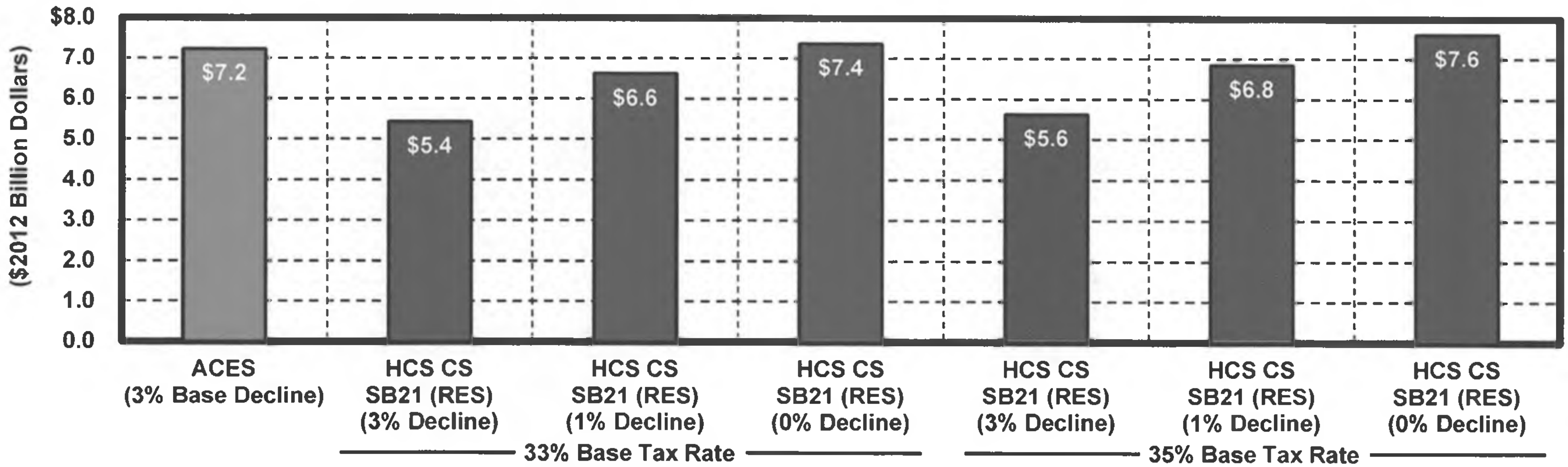


Note: All volumes over base assumed to qualify for GRE and carry 1/6th royalty.

Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios
ACES v. HCS CS SB21 (RES)
$130 West Coast ANS ($2012)

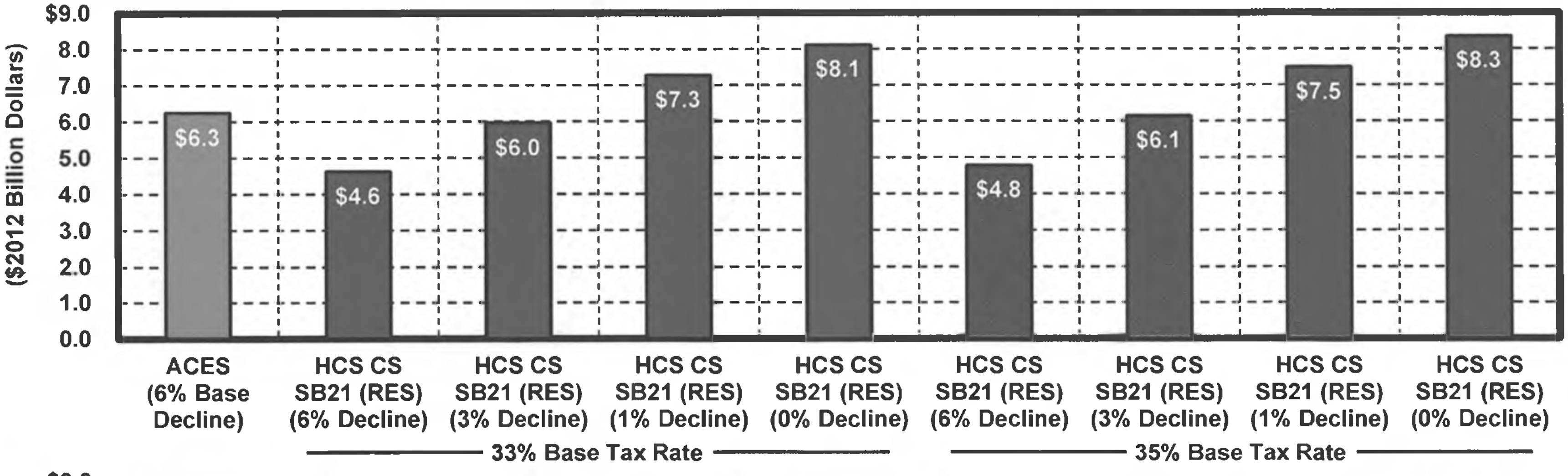
econ ONE

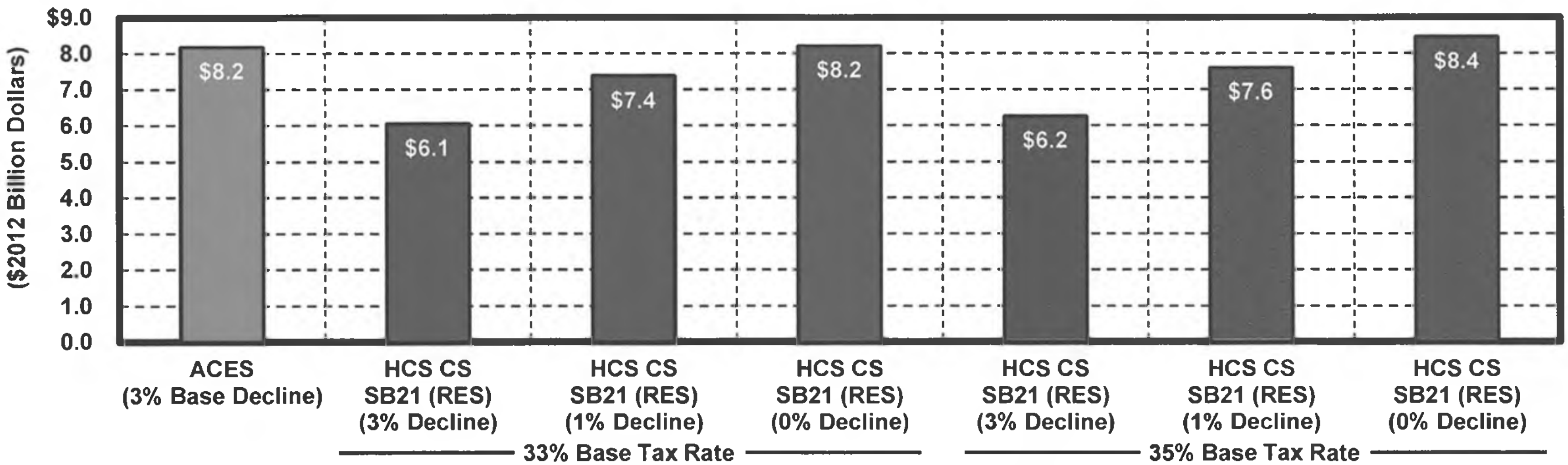




Note: All volumes over base assumed to qualify for GRE and carry 1/6th royalty.

Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios
ACES v. HCS CS SB21 (RES)
$140 West Coast ANS ($2012)

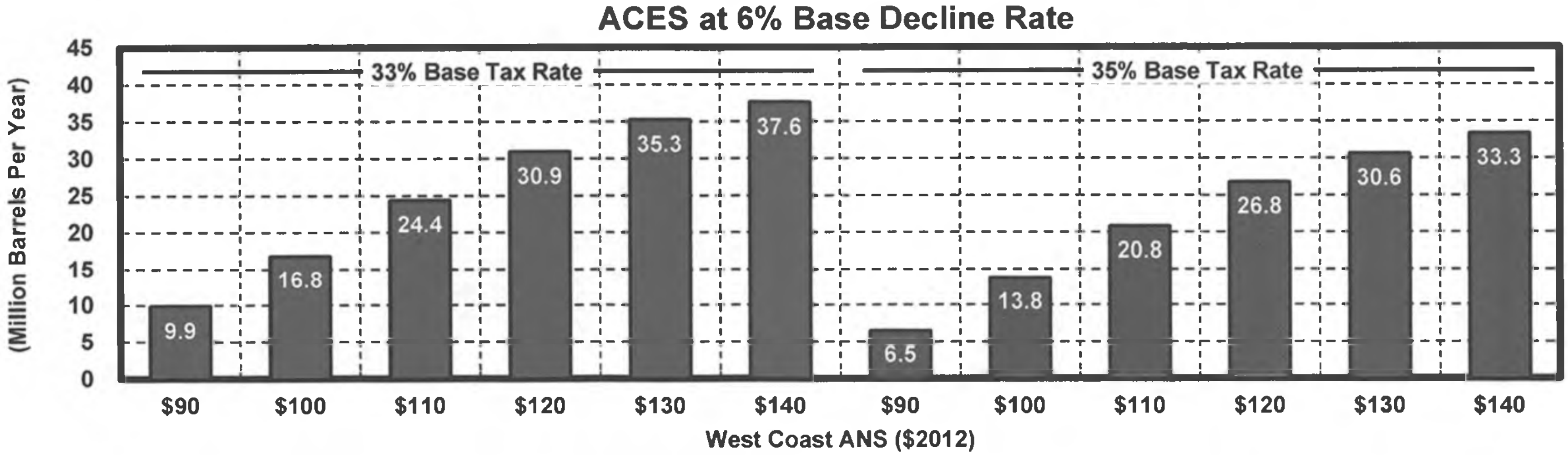


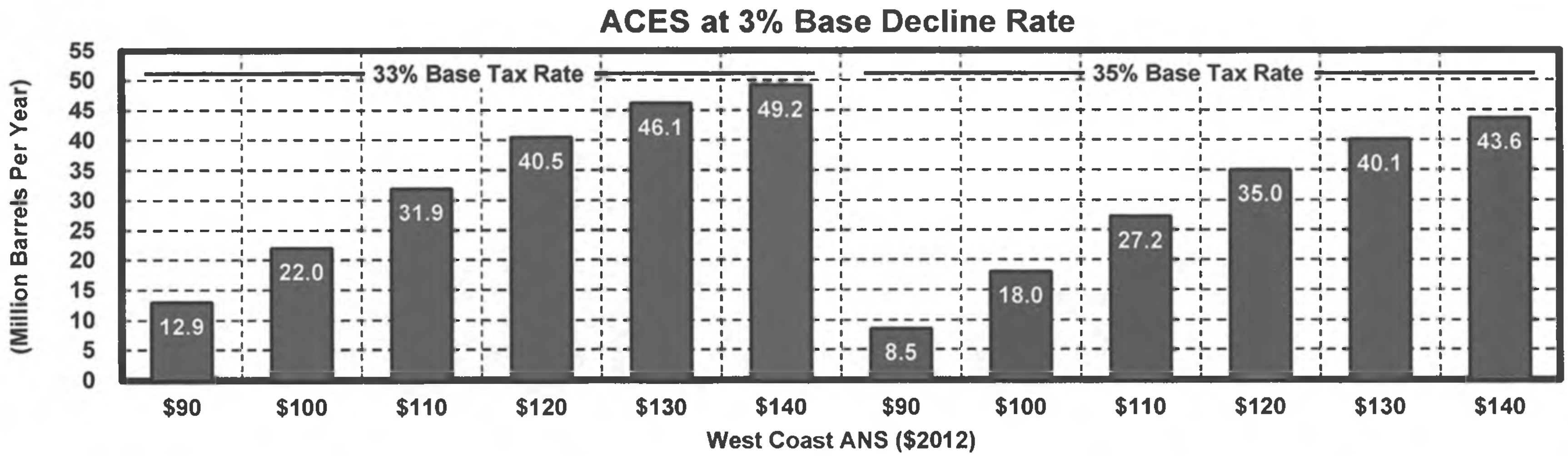


Note: All volumes over base assumed to qualify for GRE and carry 1/6th royalty.

Estimated Additional Annual Volumes Needed (2013 - 2042) Under HCS CS SB21 (RES) to Match State Oil Revenues ($2012 Billion Dollars) Under ACES at 6% and 3% Decline Rates

econ ONE





Note: All volumes over base assumed to qualify for GRE and carry 1/6th royalty.

Fiscal Impact
DRAFT HFIN CSSB21

House Finance Committee
Version 28-GS1647\L

April 11, 2013

Provisions in draft HCS CSSB21(FIN) and their Estimated Fiscal Impact as compared to Spring 2013 Forecast ($millions)[1]

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$725	-$1,400	-$1,725	-$1,875	-$1,650	-$1,525
2. Base tax rate changed to 35% of production tax value	$550	$1,050	$1,100	$1,100	$1,000	$925
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$675	$650	$525	$475	$450
4. Net operating loss credit rate increased to 45% until 1/1/16 then 35%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	$0	$0 to -$25	-$25 to -$50	-$25 to -$50	-$25 to -$50	-$50 to -$75
6. Provision requiring credits be taken over 2 years eliminated[2]	-$225					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8. Credit of $5 per taxable barrel / Sliding scale $0-$8 credit per taxable barrel based on oil price	-$425	-$825	-$775	-$750	-$700	-$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	$0	$0	$0	$0	$0	$0
11. 2016 required report to legislature	No fiscal impact					
12. Establishes competitiveness review board	No fiscal impact					
Total Revenue Impact	-$525 to -$575	-$500 to -$575	-$775 to -$850	-$1025 to -$1100	-$900 to -$975	-$875 to -$950
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits to 45% until 1/1/16 then 35%		-$80	-$80	-$40	-$40	-$40
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$675 to -$725**	**-$430 to -$505**	**-$705 to -$780**	**-$915 to -$990**	**-$790 to -$865**	**-$765 to -$840**

[1]The impacts listed are based on production and prices as forecasted in our Spring 2013 revenue forecast. The forecasted oil prices are between $109.61 and $118.29.
All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

[2]Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $375 million, with $225 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

[3]NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

Production Scenarios

Scenario A:

- New 50 Million barrel field developed by small producer without tax liability
- Peak production = 10,000 bbls/day
- Development costs = $500,000,000
- Qualifies for GRE and NOL

Production Scenarios

Scenario B:

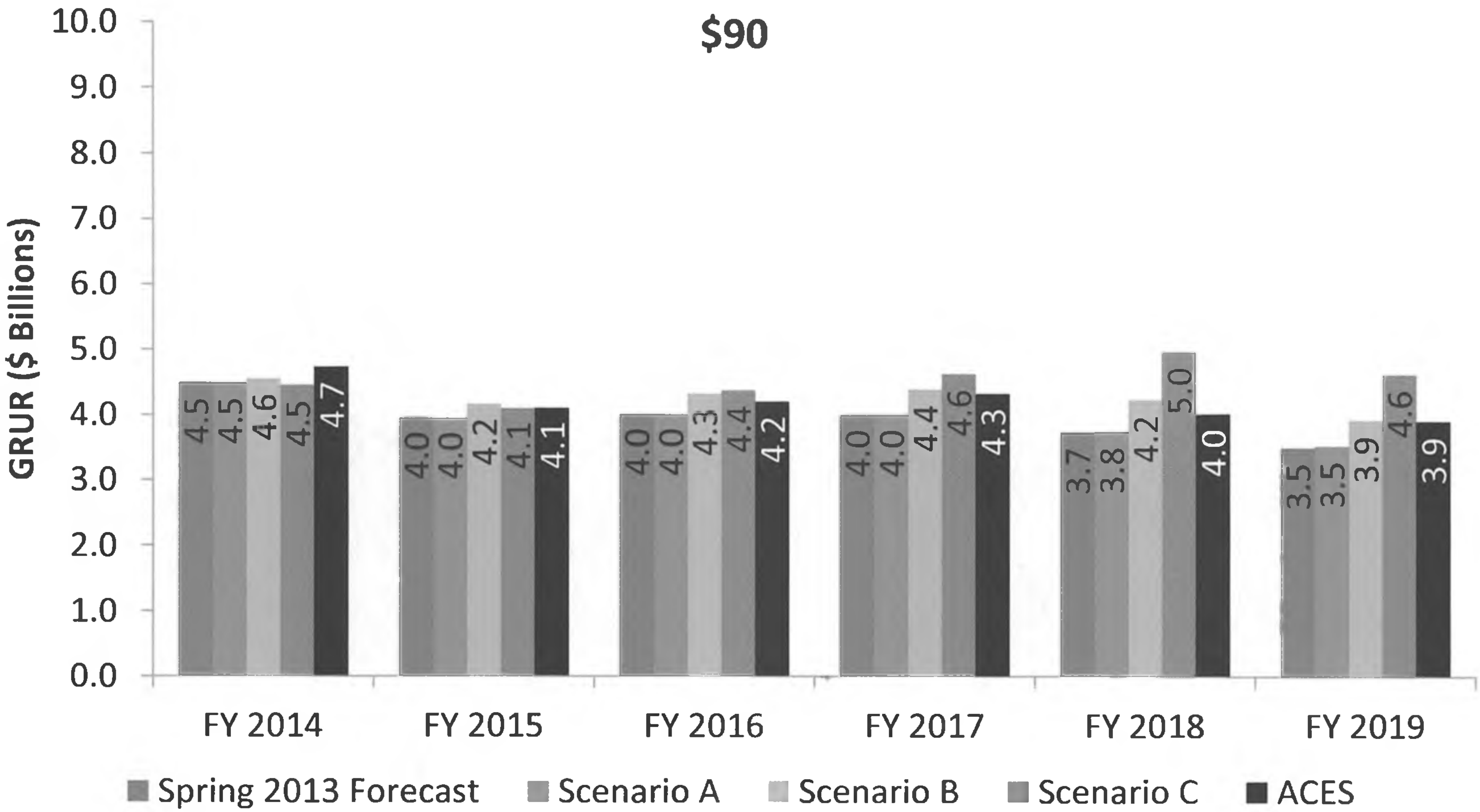
- Operators of existing units add 4 drill rigs to current plans
- Each rig adds 4,000 bbls/day in new production each year
  - Which each then decline at 15% per year
- Does not qualify for GRE

Production Scenarios

Scenario C:

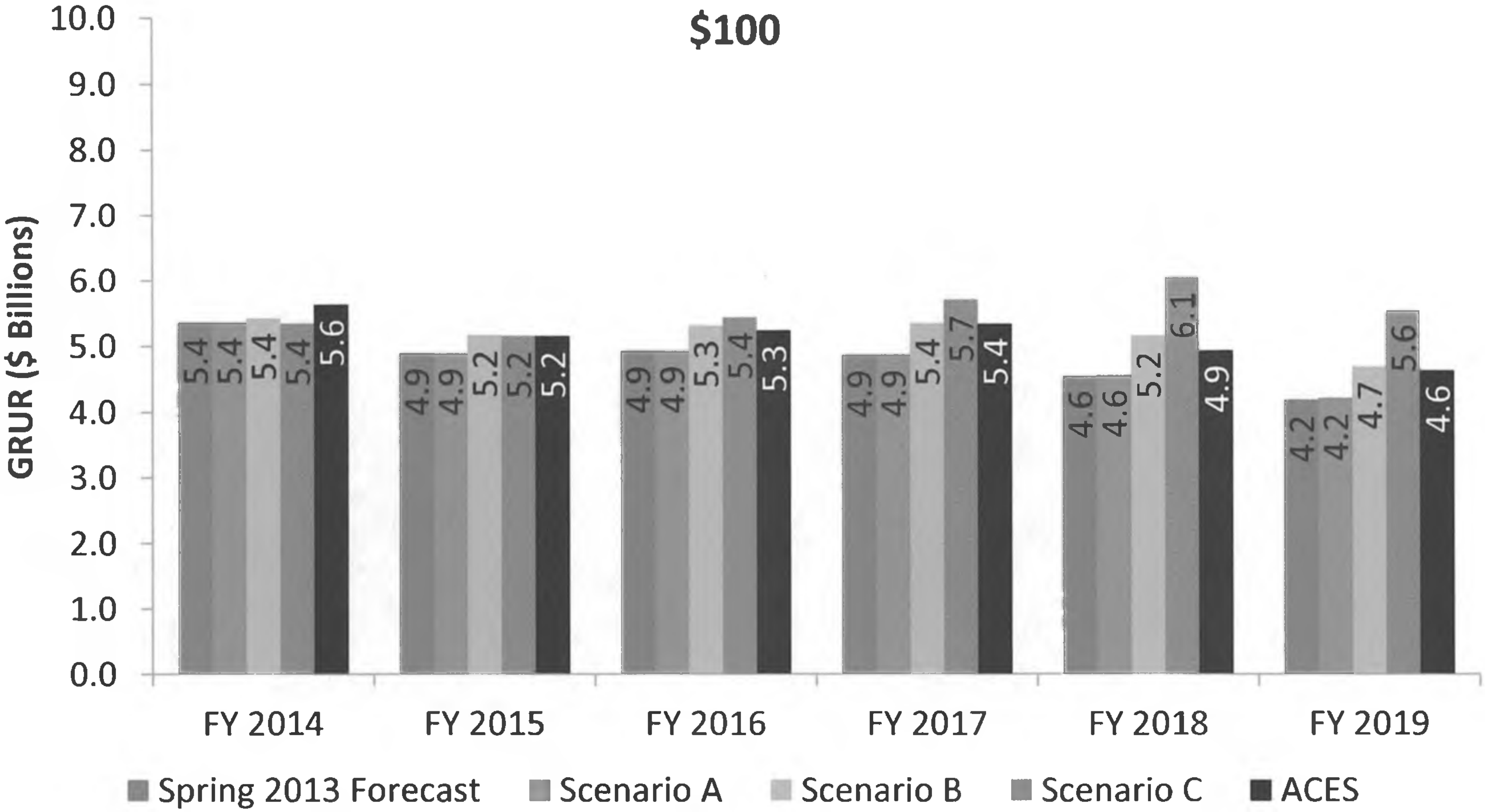
- Operator of existing legacy unit builds new drill pad
- Development cost = $5 billion
- Adds 15,000 bbls/day in 2014 increasing to peak rate of 90,000 bbls/day in 2018
- Does not qualify for GRE
- Scenario C also includes items in A and B.

Projected revenues under production scenarios – at $90 / barrel ANS



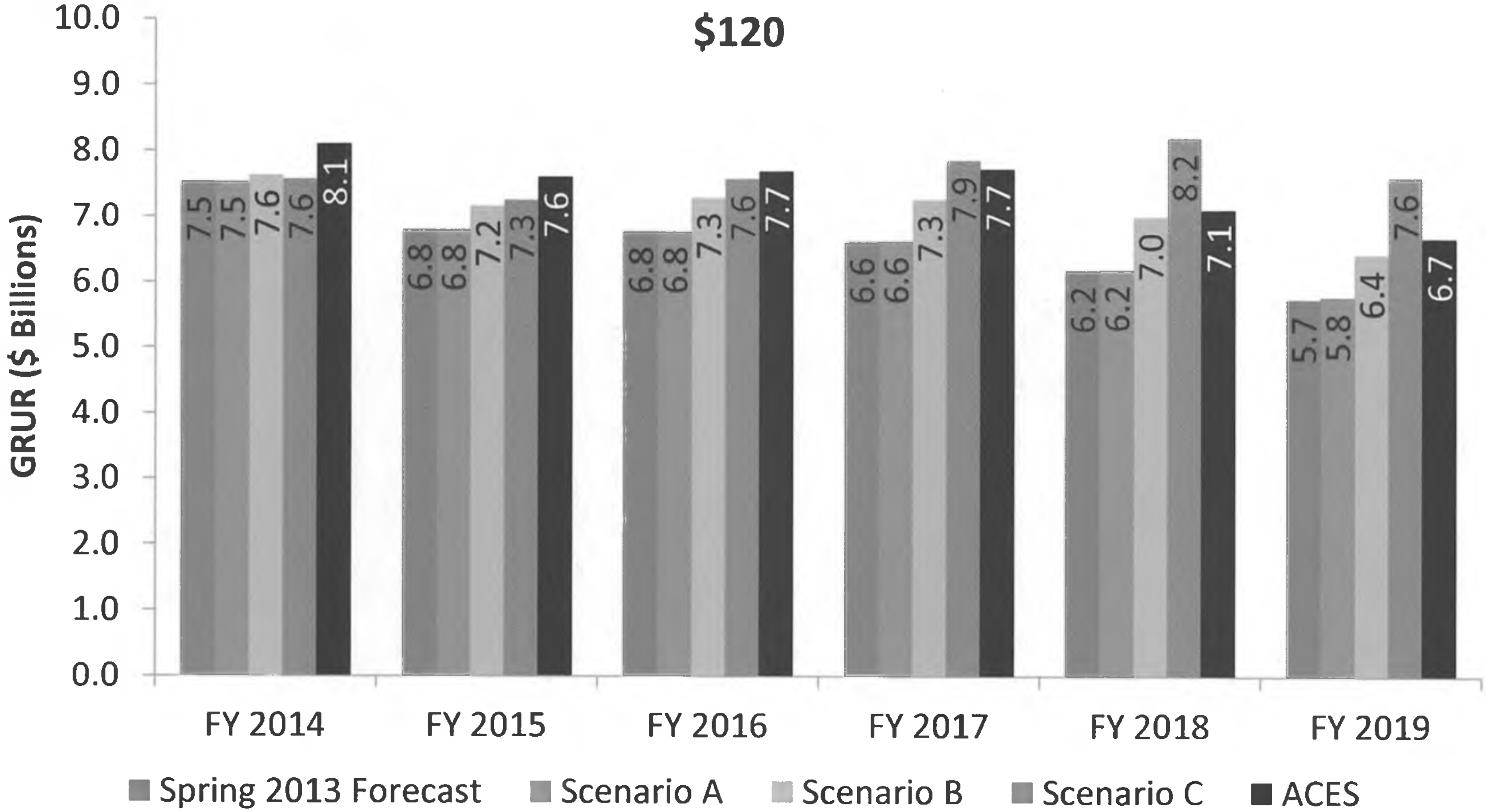
Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.

Projected revenues under production scenarios – at $100 / barrel ANS



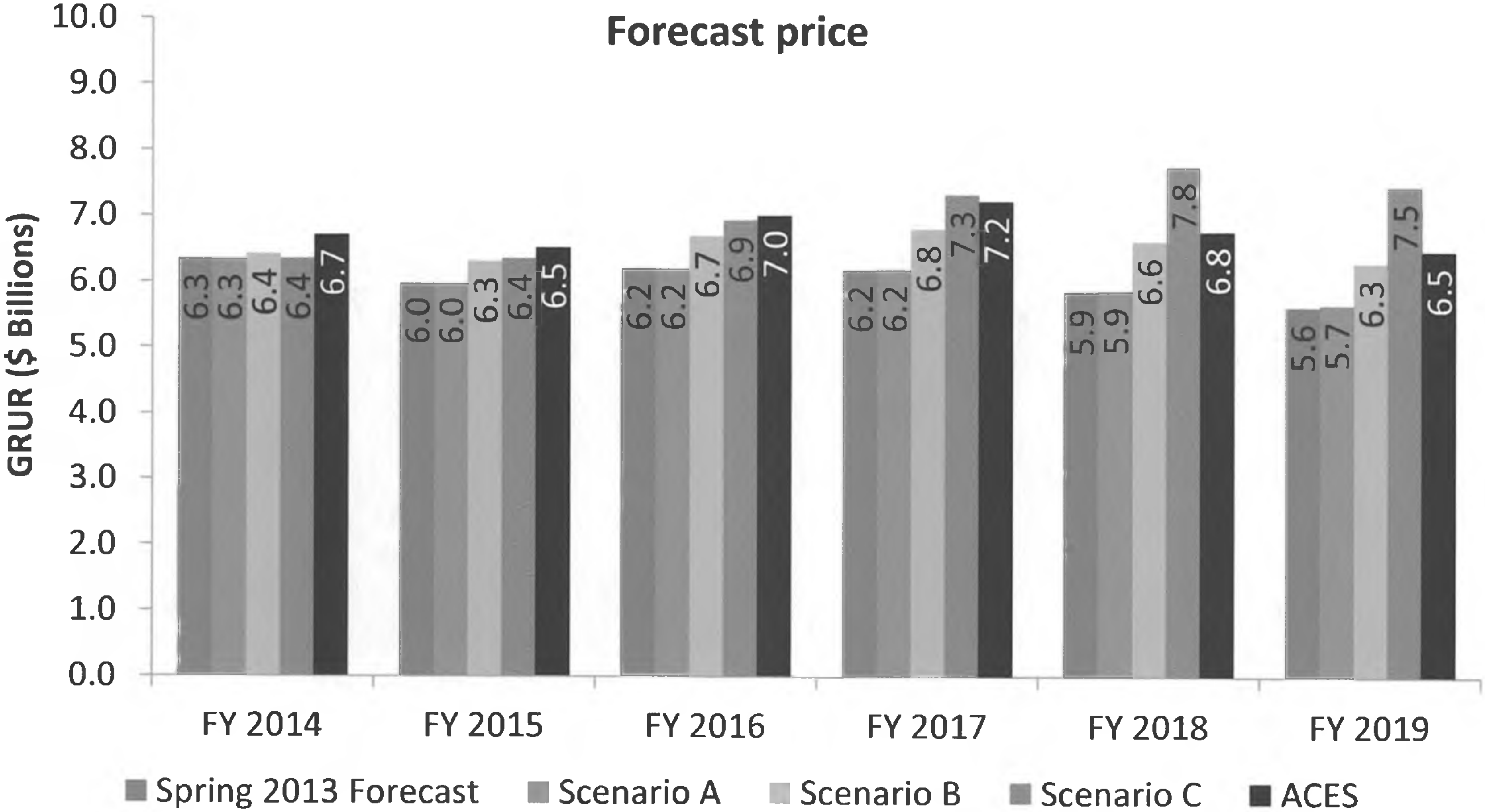
Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.

Projected revenues under production scenarios – at $120 / barrel ANS



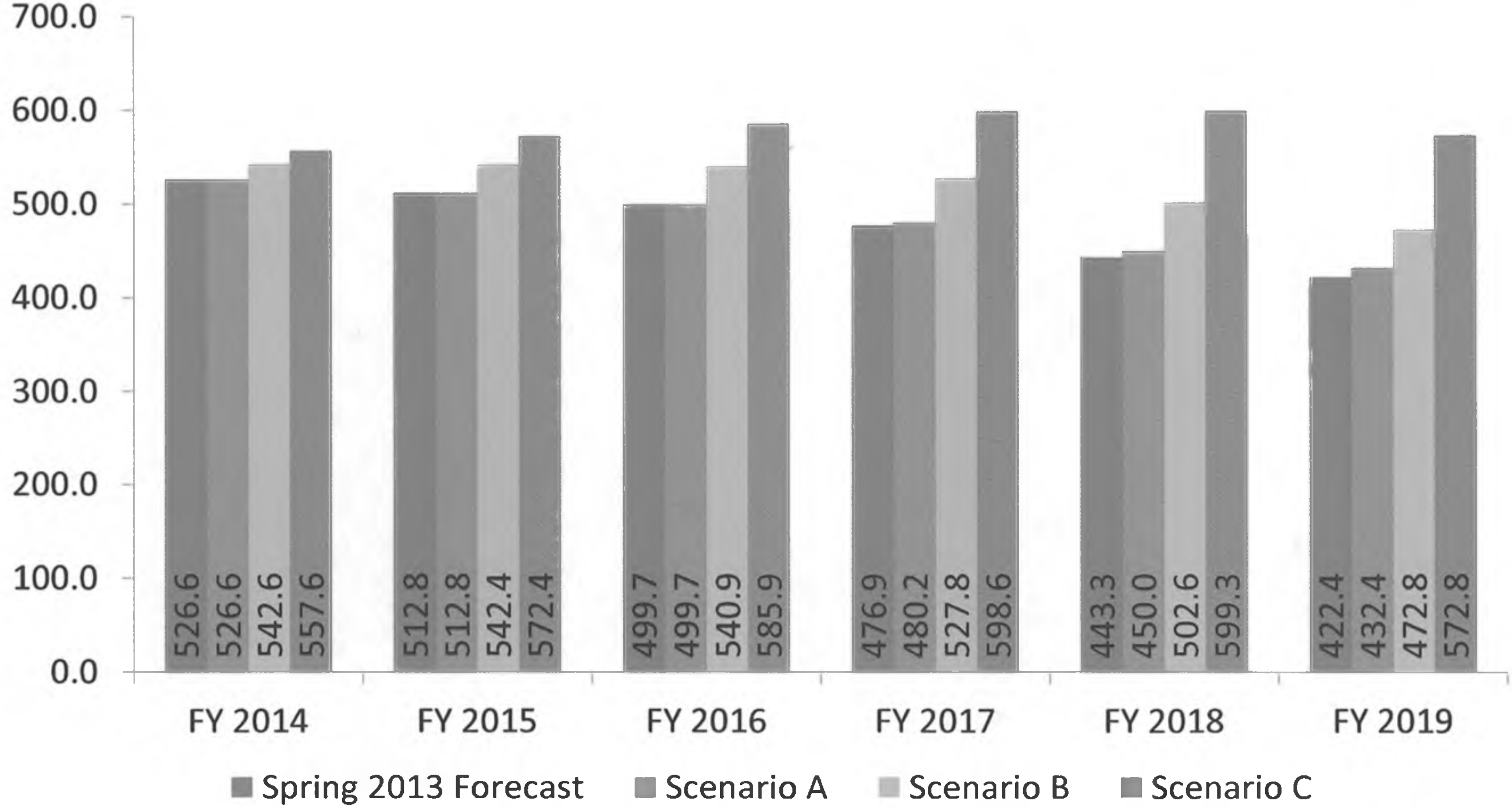
Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.

Projected revenues under production scenarios – at forecast ANS price



Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.

Production Profiles of Production Scenarios



Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.

Thank You

Analysis of HCS CS SB21 (FIN) for House Finance Committee

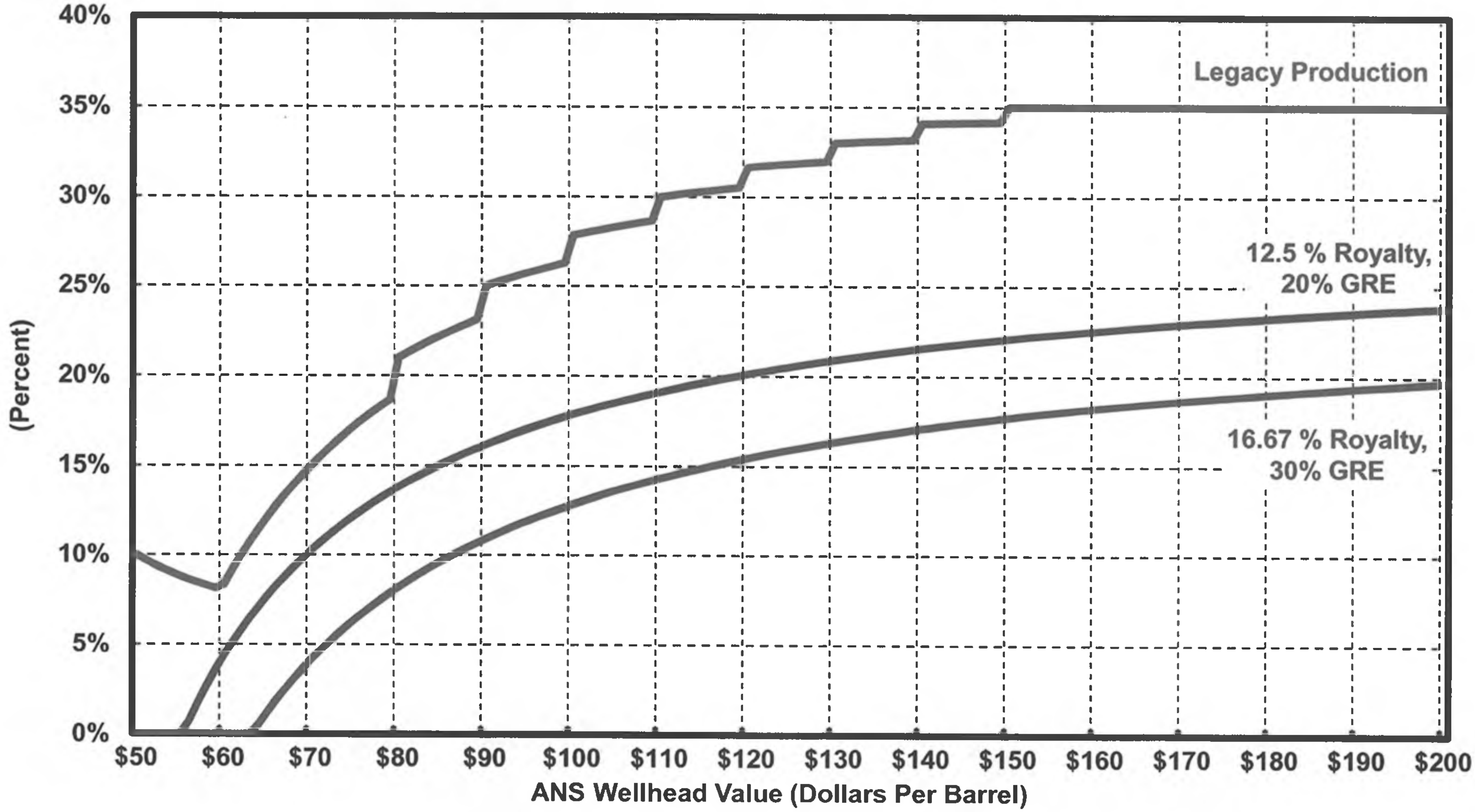
Barry Pulliam
Managing Director
Econ One Research, Inc.

April 11, 2013

Key Features of ACES, SB21/HB72 and HCS CS SB21 (RES)

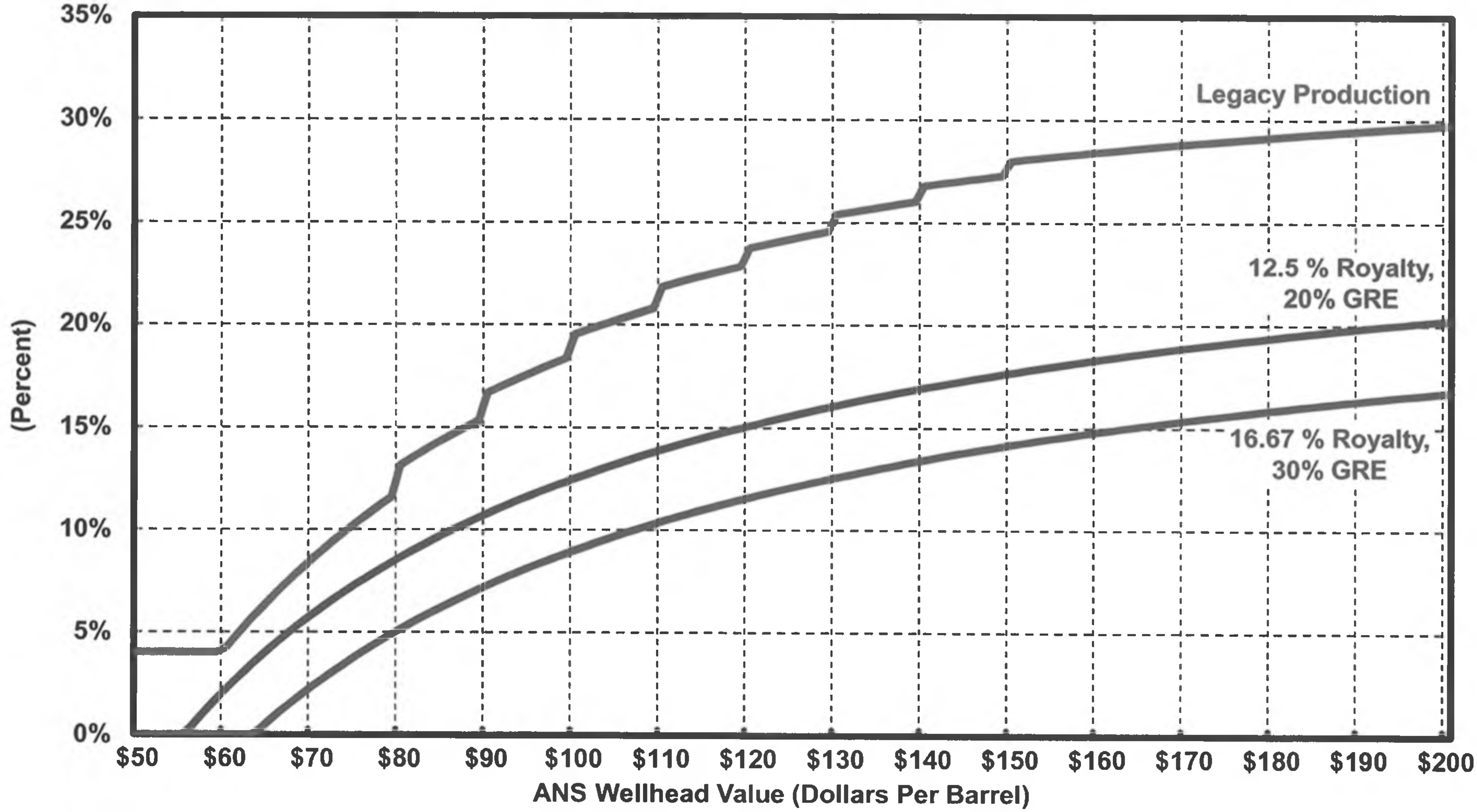
	ACES	SB71/HB72	HCS CS SB21 (RES)	HCS CS SB21 (FIN)
Base Tax Rate	25%	25%	33%	35%
Progressive Tax	0.4% Per $1 Above $30 Net; 0.1% Per $1 Above $92.50 Net	None	None	None
Maximum Tax Rate	75%	25%	33%	35%
Credits	20% of Qualified Capital Expenditure	None	Up to $8/Bbl Produced	Up to $8/Bbl Produced
Gross Revenue Exclusion (GRE)				
Rate	N/A	20%	20%	20%: 12.5% Royalty 30%: >12.5% Royalty
Applicability		New Units/PAs	New Units/PAs PA Expansions	New Units/PAs PA Expansions
Monetization of Net Operating Losses (NOLs)	Yes	No Carried Forward With 15% Increase	Yes	Yes 45% Through 2015, 35% Thereafter
Minimum Tax	4% of Gross @ WC ANS > $25	4% of Gross @ WC ANS > $25	4% of Gross @ WC ANS > $25	4% of Gross @ WC ANS > $25
Credits Reduce Minimum Tax	Yes	N/A	GRE Barrels Only	GRE Barrels Only
Small Producer Credit	$12 Million (2016)	$12 Million (2022)	$12 Million (2022)	$12 Million (2016)

Effective Net Tax Rates Under HCS CS SB21 (FIN)



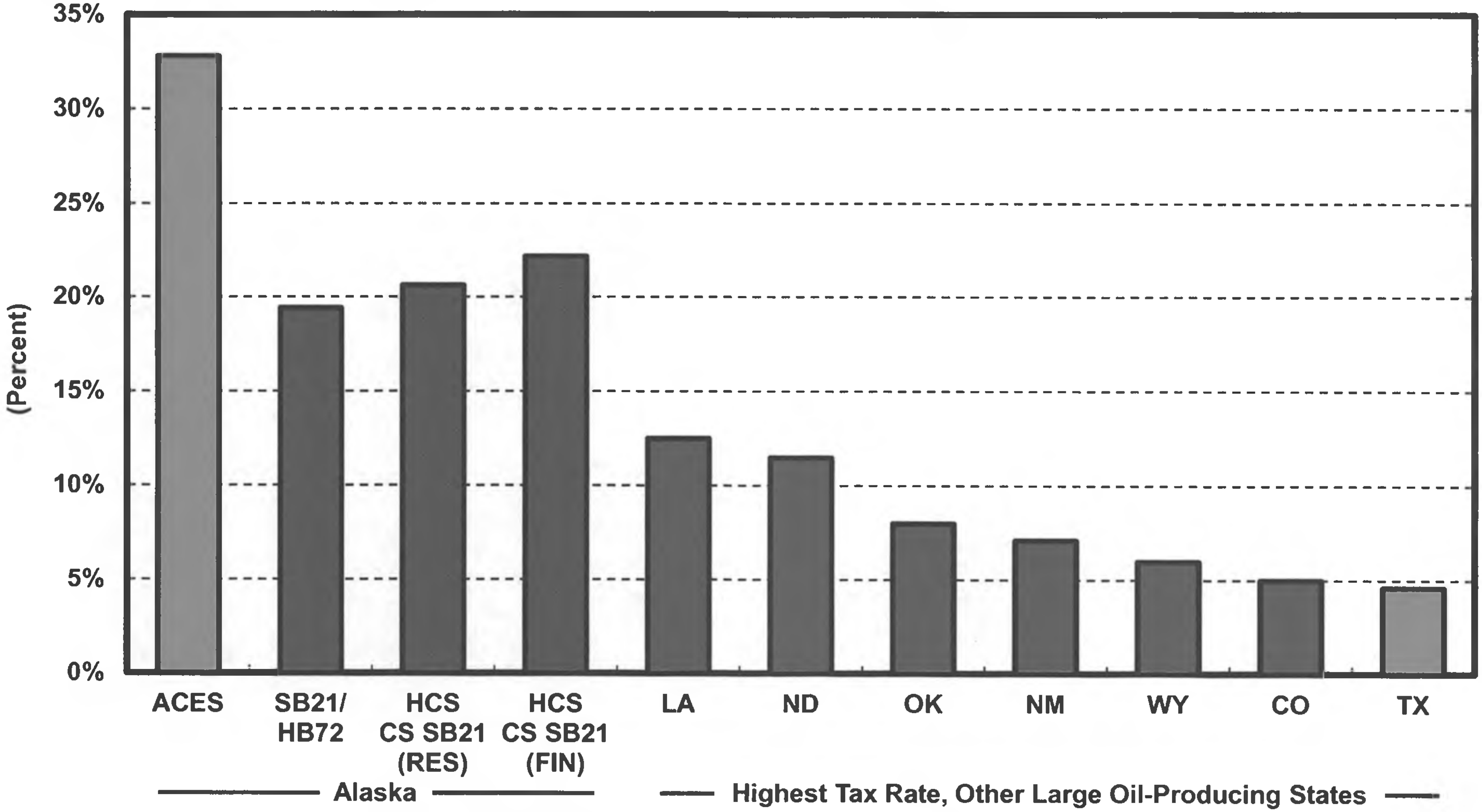
Note: Under HCS CS SB21 (FIN), per barrel credit is equal to $8/Bbl at wellhead prices below $80/bbl, diminishing to $0/Bbl at a wellhead price of $150/bbl. The minimum tax is 4% of the wellhead value of the oil whenever West Coast ANS is above $25/Bbl for non-GRE barrels.

Effective Gross Tax Rates Under HCS CS SB21 (FIN)



Note: Under HCS CS SB21 (FIN), per barrel credit is equal to $8/Bbl at wellhead prices below $80/bbl, diminishing to $0/Bbl at a wellhead price of $150/bbl. The minimum tax is 4% of the wellhead value of the oil whenever West Coast ANS is above $25/Bbl for non-GRE barrels.

Effective Tax Rates on Gross Value for Legacy Production ACES vs. SB21/HB72, HCS CS SB21 (FIN) and Other Large Oil-Producing States With Production Taxes at $100 Wellhead Value*



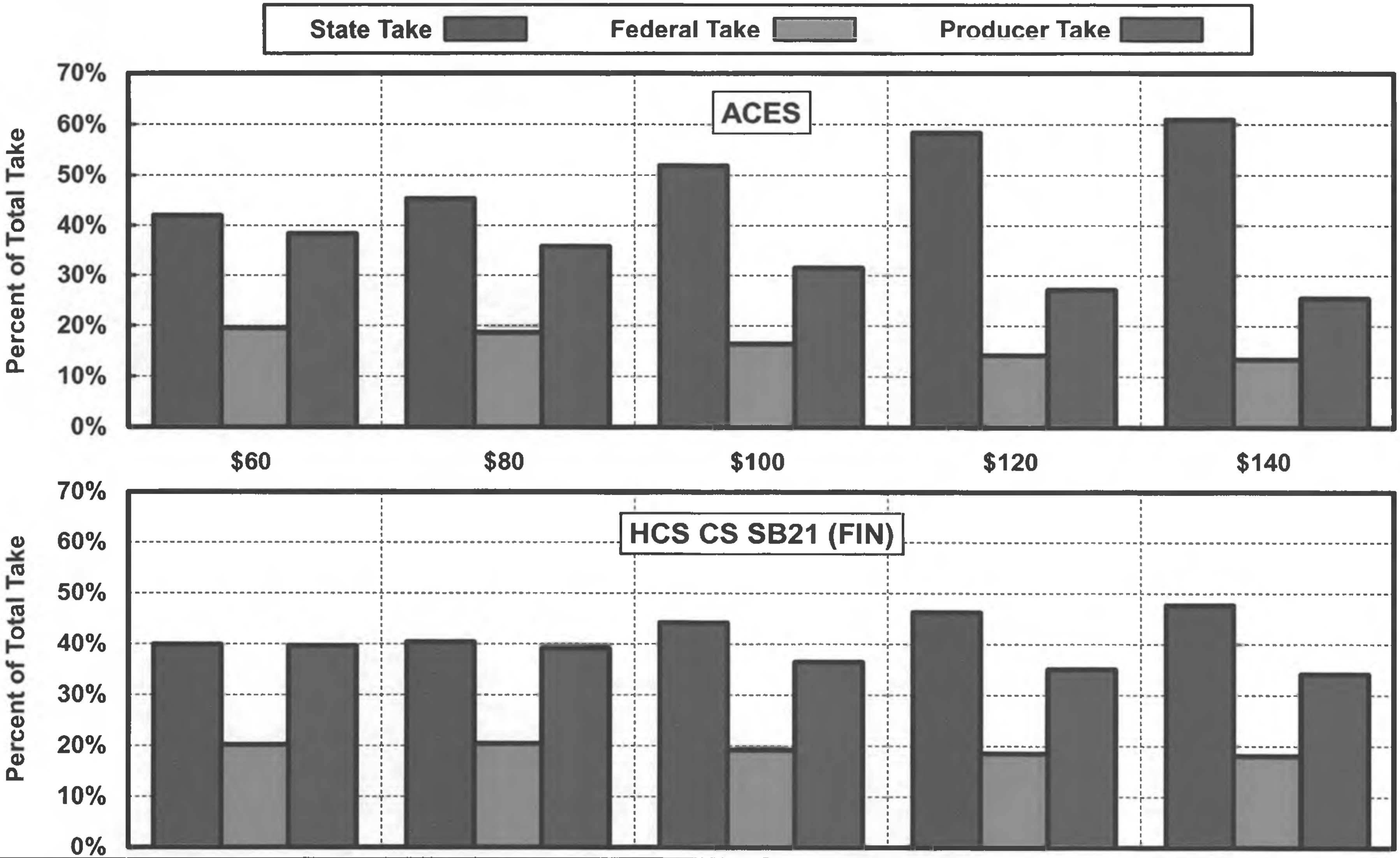
Note: California and Federal Offshore properties are not subject to a severance tax.
* FY2012 Combined PBU/KPU Costs and Volumes

Average Government Take for All Existing Producers (FY2015-FY2019)

$2012 West Coast ANS Price	Government Take HB72/SB21	CS SB21 (FIN)	HCS CS SB21 (RES)	HCS CS SB21 (FIN)	ACES
($2012 $/Bbl)	(Percent)				
(1)	(2)	(3)	(4)	(5)	(7)
$60	67.9%	63.0%	60.3%	60.7%	61.6%
$70	65.7%	63.7%	59.6%	60.3%	62.2%
$80	64.5%	64.1%	60.9%	61.8%	64.1%
$90	63.7%	64.3%	62.3%	63.3%	66.2%
$100	63.2%	64.5%	63.5%	64.4%	68.5%
$110	62.8%	64.7%	64.3%	65.3%	70.7%
$120	62.5%	64.8%	64.9%	65.9%	72.8%
$130	62.3%	64.9%	65.4%	66.4%	73.8%
$140	62.1%	65.0%	65.9%	66.9%	74.5%
$150	62.0%	65.0%	66.0%	67.0%	75.1%
$160	61.8%	65.1%	65.9%	66.9%	75.7%

Note: Under HCS CS SB21 (RES) and HCS CS SB21 (FIN), per barrel credit is equal to $8/Bbl at wellhead prices below $80/bbl, diminishing to $0/Bbl at a wellhead price of $150/bbl. The minimum tax is 4% of the wellhead value of the oil whenever West Coast ANS is above $25/Bbl for non-GRE barrels.

State, Federal and Producer Take at Various $2012 WC ANS Prices for All Producers (FY 2015 - FY 2019) ACES and HCS CS SB21 (FIN)



Summary of Investment Measures for New Participant
50 MMBO Alaska Oil Development
ACES and HCS CS SB21 (FIN) v. Benchmark Areas

Real $2012 West Coast ANS Price	ACES 16.67% Royalty	HCS CS SB21 (FIN) 35% Base Rate, $5/Bbl Credit — 12.5% Royalty: 20% GRE	HCS CS SB21 (FIN) 35% Base Rate, $5/Bbl Credit — 16.67% Royalty: 30% GRE	Unconventional Lower-48 Eagle Ford	Unconventional Lower-48 Bakken	Offshore GOM	Canada Oil Sands SAGD	Norway	United Kingdom Pre-1993 w/ Brownfield Allowance*	United Kingdom Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Producer NPV-12 / BOE (Dollars Per BOE)										
$80	$2.28	$3.33	$3.08	$3.61	$0.67	$2.80	($0.93)	$0.24	$4.81	$4.62
$100	$4.17	$6.75	$6.54	$6.75	$4.29	$6.22	$0.46	$2.34	$7.09	$8.25
$120	$5.79	$10.13	$10.06	$11.17	$9.16	$9.64	$2.01	$4.44	$9.09	$11.88
Profitability Index-12										
$80	1.18	1.27	1.25	1.25	1.04	1.25	0.88	1.01	1.22	1.21
$100	1.33	1.54	1.52	1.47	1.28	1.55	1.06	1.14	1.33	1.38
$120	1.46	1.81	1.80	1.78	1.60	1.85	1.26	1.27	1.42	1.55
IRR (Percent)										
$80	18.4%	19.7%	19.1%	29.9%	13.6%	18.3%	9.7%	12.4%	34.5%	24.7%
$100	23.3%	26.2%	25.7%	46.3%	22.7%	24.3%	13.1%	16.0%	45.2%	32.9%
$120	26.9%	31.8%	31.7%	73.6%	37.0%	29.3%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)										
$80	$20.82	$23.28	$22.28	$23.39	$28.39	$26.31	$26.07	$34.51	$22.94	$29.35
$100	$26.78	$33.20	$32.46	$29.99	$36.48	$37.34	$29.14	$39.42	$28.85	$37.82
$120	$30.79	$42.30	$42.11	$36.87	$44.91	$48.37	$33.37	$44.32	$31.29	$46.30
Government Take (Percent)										
$80	70.4%	59.6%	60.7%	71.7%	77.1%	55.7%	63.4%	67.8%	61.0%	52.0%
$100	73.9%	60.0%	60.6%	67.9%	72.1%	52.6%	63.5%	71.7%	68.6%	55.8%
$120	76.0%	60.4%	60.6%	65.1%	68.7%	50.9%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)										
$80	$6.06	$4.44	$4.83	-	-	-	-	-	-	-
$100	$11.80	$7.84	$8.15	-	-	-	-	-	-	-
$120	$17.96	$11.28	$11.39	-	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.

Alaska Oil Development : New development profile and costs are based on Pioneer's presentation dated February 18, 2013 -- $18/Bbl. Development Capex.

Appendix

Tax Calculation Using Stepped Scale Production Credit (Volumes Not Subject to Gross Revenue Exclusion)

(a) West Coast Price ($/Bbl)			$80.00	$100.00	$120.00	$140.00	$160.00
(b) Transportation ($/Bbl)		-	10.00	10.00	10.00	10.00	10.00
(c) Gross Value ($/Bbl)	(a) - (b)	=	$70.00	$90.00	$110.00	$130.00	$150.00
(d) Lease Expenditures ($/Bbl)		-	30.00	30.00	30.00	30.00	30.00
(e) Net Value ($/Bbl)	(c) - (d)	=	$40.00	$60.00	$80.00	$100.00	$120.00
(f) Tax Rate (Percent)		x	35%	35%	35%	35%	35%
(g) Production Tax Before Credit ($/Bbl)	(e) x (f)		$14.00	$21.00	$28.00	$35.00	$42.00
(h) Production Credit ($/Bbl)		-	8.00	6.00	4.00	2.00	0.00
(i) Production Tax After Credit ($/Bbl)	(g) - (h)		$6.00	$15.00	$24.00	$33.00	$42.00
(j) Taxable Barrels (Bbls)		x	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
(k) Total Production Tax After Credit ($000)	(i) x (j)	=	$6,000	$15,000	$24,000	$33,000	$42,000
(l) Effective Tax Rate on Net Value (%)	(i) ÷ (e)		15.0%	25.0%	30.0%	33.0%	35.0%
(m) Effective Tax Rate on Gross Value (%)	(i) ÷ (c)		8.6%	16.7%	21.8%	25.4%	28.0%

Note: Per barrel credit is equal to $8/Bbl at wellhead prices below $80/bbl, diminishing to $0/Bbl at a wellhead price of $150/bbl.
The minimum tax is 4% of the wellhead value of the oil whenever West Coast ANS is above $25/Bbl.

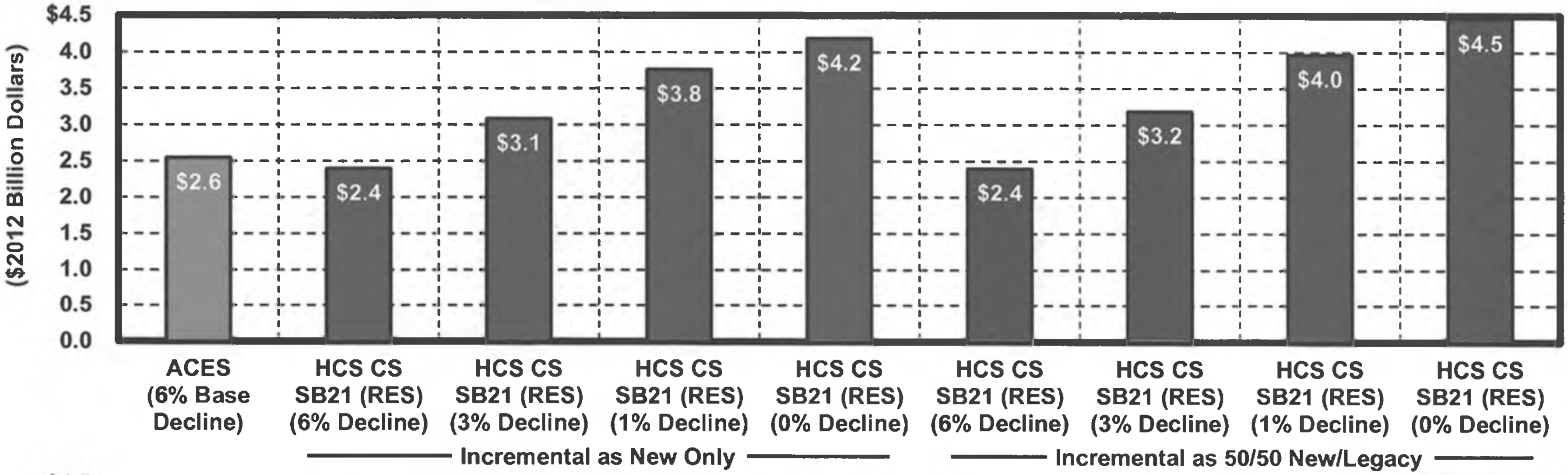
Tax Calculation Using Fixed $5 Production Credit (Volumes Subject to Gross Revenue Exclusion, 12.5% Royalty)

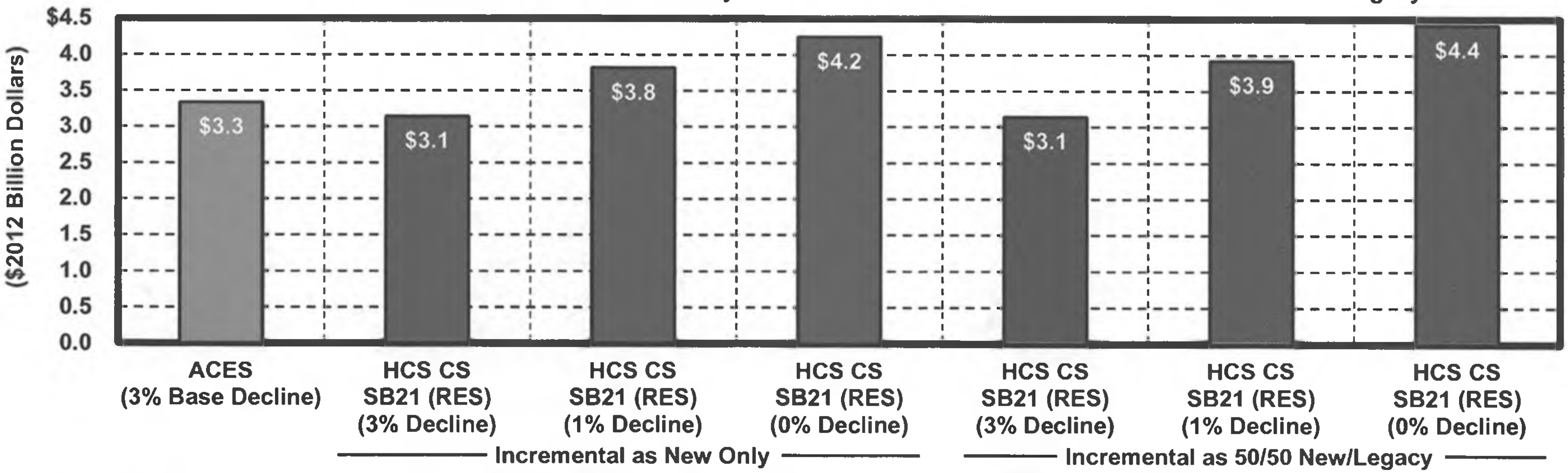
(a) West Coast Price ($/Bbl)			$80.00	$100.00	$120.00	$140.00	$160.00
(b) Transportation ($/Bbl)		-	10.00	10.00	10.00	10.00	10.00
(c) Gross Value ($/Bbl)	(a) - (b)	=	$70.00	$90.00	$110.00	$130.00	$150.00
(d) Lease Expenditures ($/Bbl)		-	30.00	30.00	30.00	30.00	30.00
(e) Net Value ($/Bbl)	(c) - (d)	=	$40.00	$60.00	$80.00	$100.00	$120.00
(f) Gross Revenue Exclusion (%)			20%	20%	20%	20%	20%
(g) Gross Value After GRE ($/Bbl)	(c) x [100%-(h)]		$56.00	$72.00	$88.00	$104.00	$120.00
(h) Net Value After GRE ($/Bbl)	(g) - (d)		$26.00	$42.00	$58.00	$74.00	$90.00
(i) Tax Rate (Percent)		x	35%	35%	35%	35%	35%
(j) Production Tax Before Credit ($/Bbl)	(h) x (i)	=	$9.10	$14.70	$20.30	$25.90	$31.50
(k) Production Credit ($/Bbl)		-	5.00	5.00	5.00	5.00	5.00
(l) Production Tax After Credit ($/Bbl)	(j) - (k)	=	$4.10	$9.70	$15.30	$20.90	$26.50
(m) Taxable Barrels (Bbls)		x	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
(n) Total Production Tax After Credit ($000)	(l) x (m)	=	$4,100	$9,700	$15,300	$20,900	$26,500
(o) Effective Tax Rate on Net Value (%)	(l) ÷ (e)		10.3%	16.2%	19.1%	20.9%	22.1%
(p) Effective Tax Rate on Gross Value (%)	(l) ÷ (c)		5.9%	10.8%	13.9%	16.1%	17.7%

Tax Calculation Using Fixed $5 Production Credit (Volumes Subject to Gross Revenue Exclusion, >12.5% Royalty)

(a)	West Coast Price ($/Bbl)			$80.00	$100.00	$120.00	$140.00	$160.00
(b)	Transportation ($/Bbl)		-	10.00	10.00	10.00	10.00	10.00
(c)	Gross Value ($/Bbl)	(a) - (b)	=	$70.00	$90.00	$110.00	$130.00	$150.00
(d)	Lease Expenditures ($/Bbl)		-	30.00	30.00	30.00	30.00	30.00
(e)	Net Value ($/Bbl)	(c) - (d)	=	$40.00	$60.00	$80.00	$100.00	$120.00
(f)	Gross Revenue Exclusion (%)			30%	30%	30%	30%	30%
(g)	Gross Value After GRE ($/Bbl)	(c) x [100%-(h)]		$49.00	$63.00	$77.00	$91.00	$105.00
(h)	Net Value After GRE ($/Bbl)	(g) - (d)		$19.00	$33.00	$47.00	$61.00	$75.00
(i)	Tax Rate (Percent)		x	35%	35%	35%	35%	35%
(j)	Production Tax Before Credit ($/Bbl)	(h) x (i)	=	$6.65	$11.55	$16.45	$21.35	$26.25
(k)	Production Credit ($/Bbl)		-	5.00	5.00	5.00	5.00	5.00
(l)	Production Tax After Credit ($/Bbl)	(j) - (k)	=	$1.65	$6.55	$11.45	$16.35	$21.25
(m)	Taxable Barrels (Bbls)		x	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
(n)	Total Production Tax After Credit ($000)	(l) x (m)	=	$1,650	$6,550	$11,450	$16,350	$21,250
(o)	Effective Tax Rate on Net Value (%)	(l) ÷ (e)		4.1%	10.9%	14.3%	16.4%	17.7%
(p)	Effective Tax Rate on Gross Value (%)	(l) ÷ (c)		2.4%	7.3%	10.4%	12.6%	14.2%

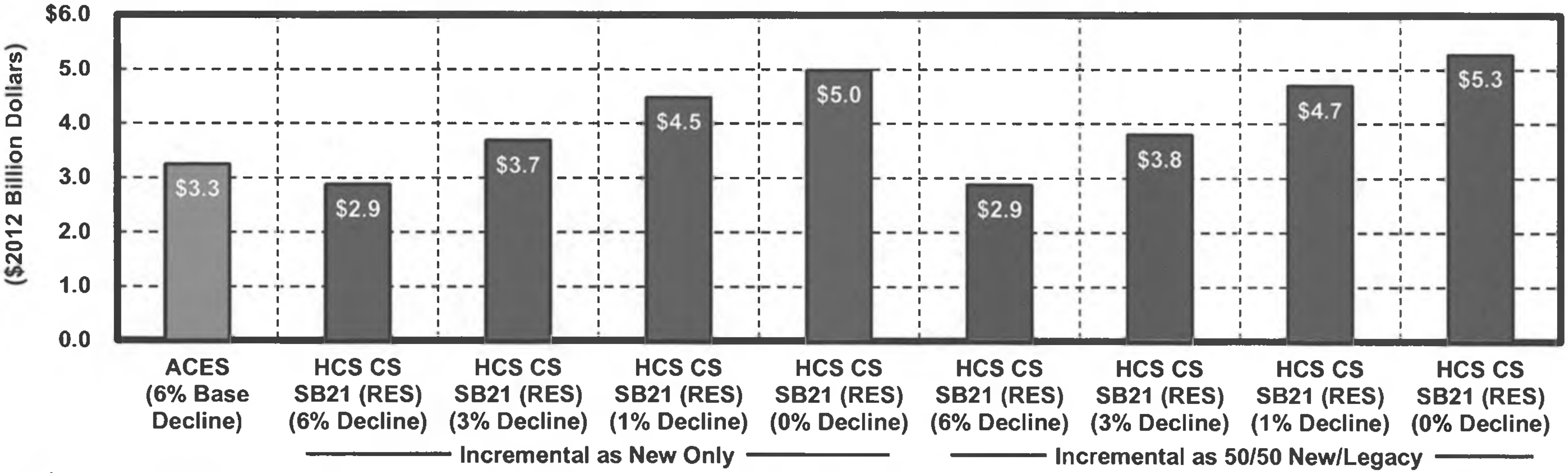
Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (~~RES~~ FMN) Alternative (35% Base Rate, 30% GRE) $90 West Coast ANS ($2012)

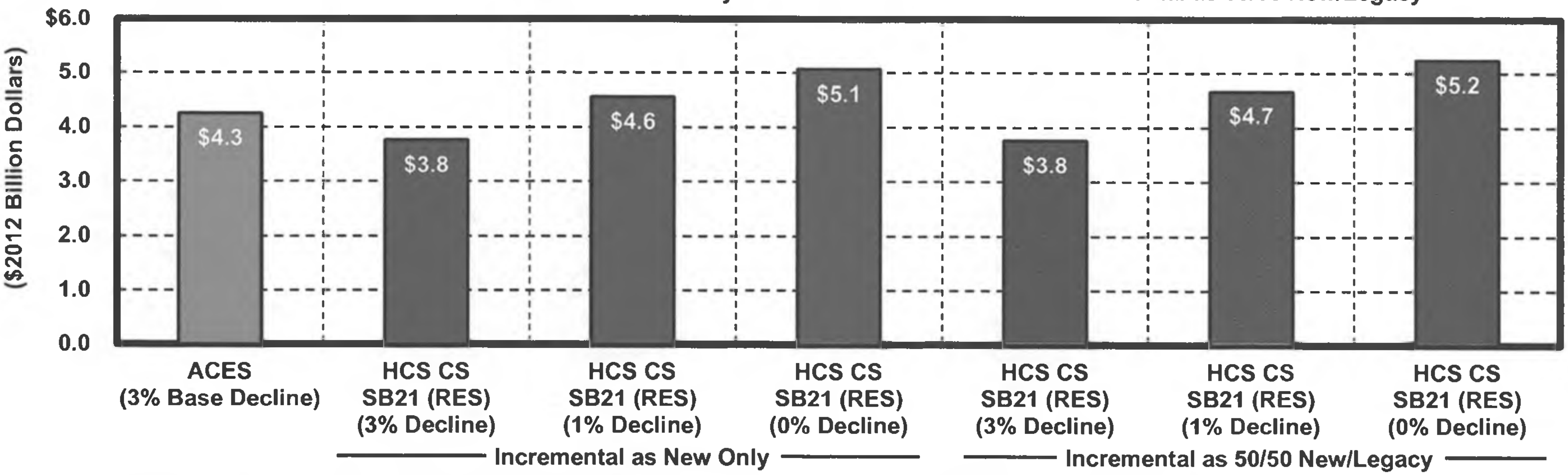




Note: Volumes over base classified as "new" assumed to qualify for GRE and carry 1/6th royalty; volumes over base classified as "legacy" assumed in PBU/KPU fields.

Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (~~RES~~ F/N) Alternative (35% Base Rate, 30% GRE) $100 West Coast ANS ($2012)

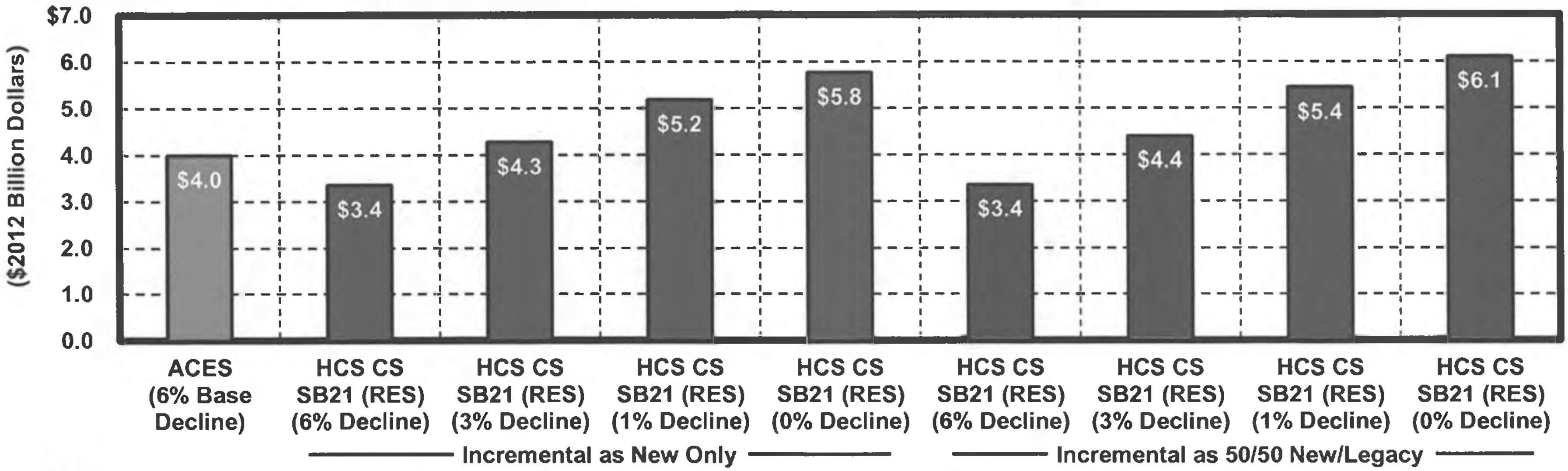


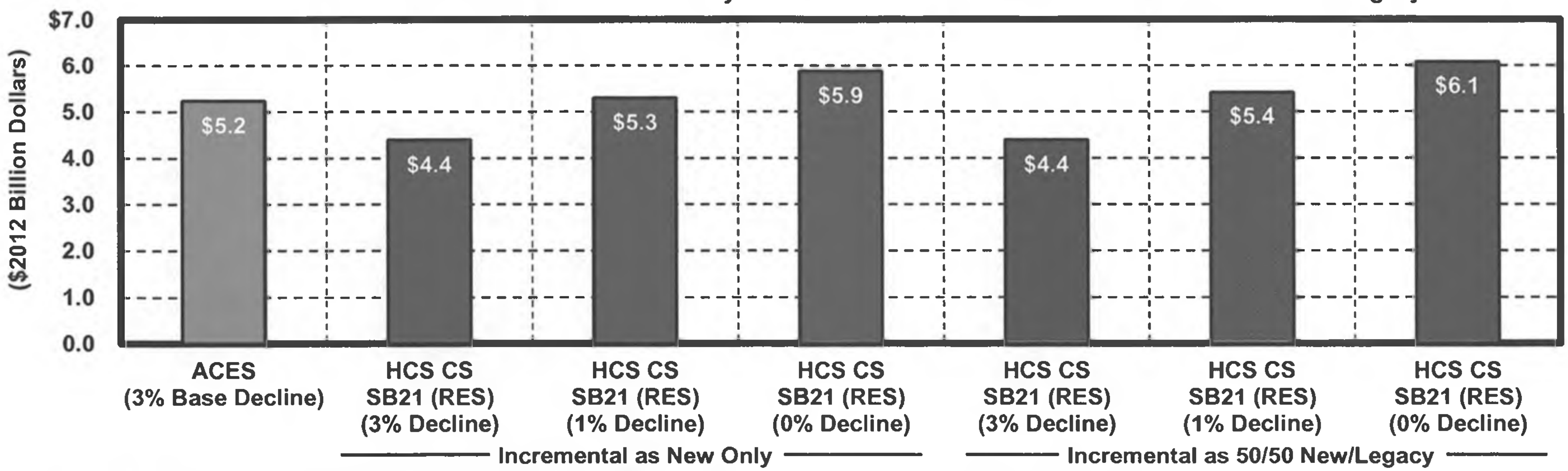


Note: Volumes over base classified as "new" assumed to qualify for GRE and carry 1/6th royalty; volumes over base classified as "legacy" assumed in PBU/KPU fields.

Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 ~~(RES)~~ FIN Alternative (35% Base Rate, 30% GRE) $110 West Coast ANS ($2012)

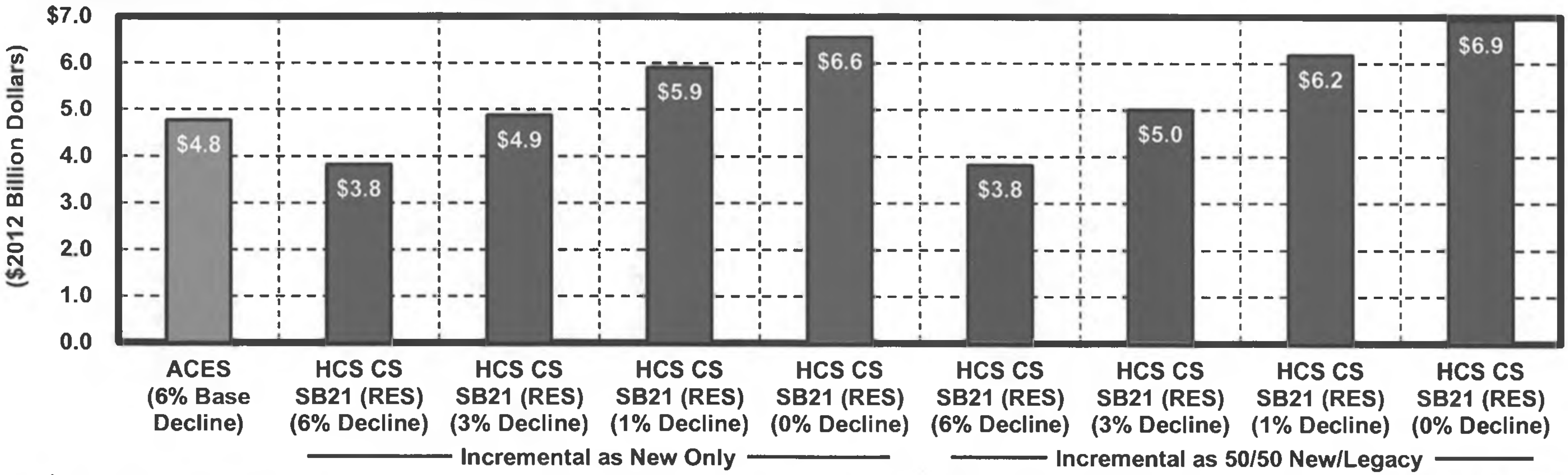
econ ONE

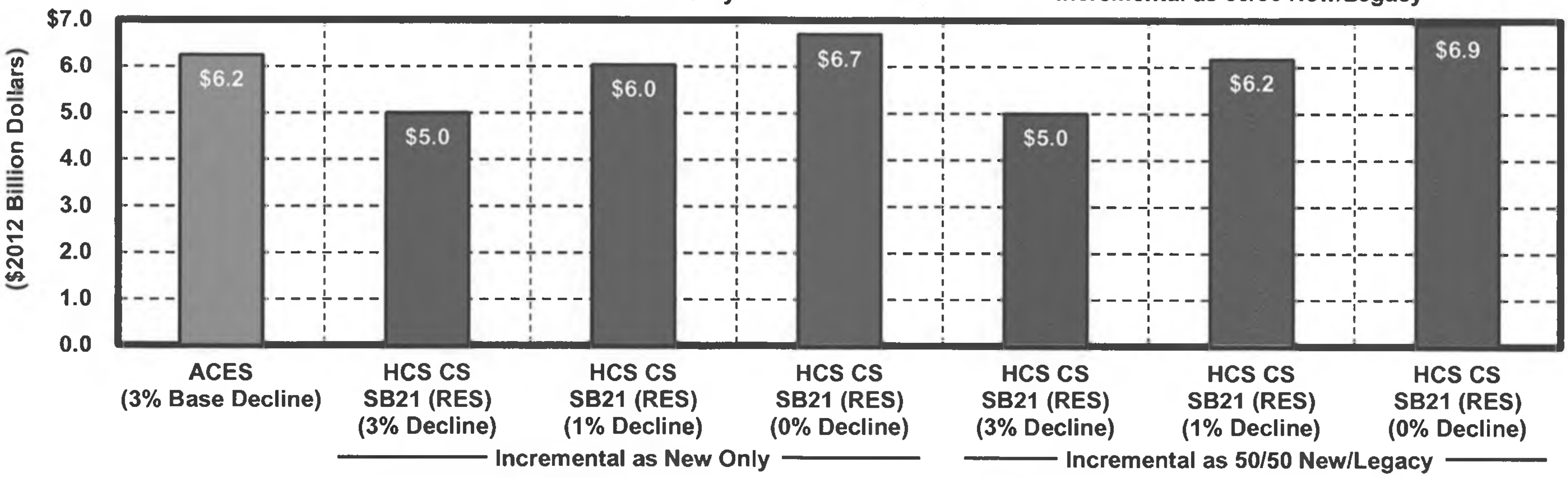




Note: Volumes over base classified as "new" assumed to qualify for GRE and carry 1/6th royalty; volumes over base classified as "legacy" assumed in PBU/KPU fields.

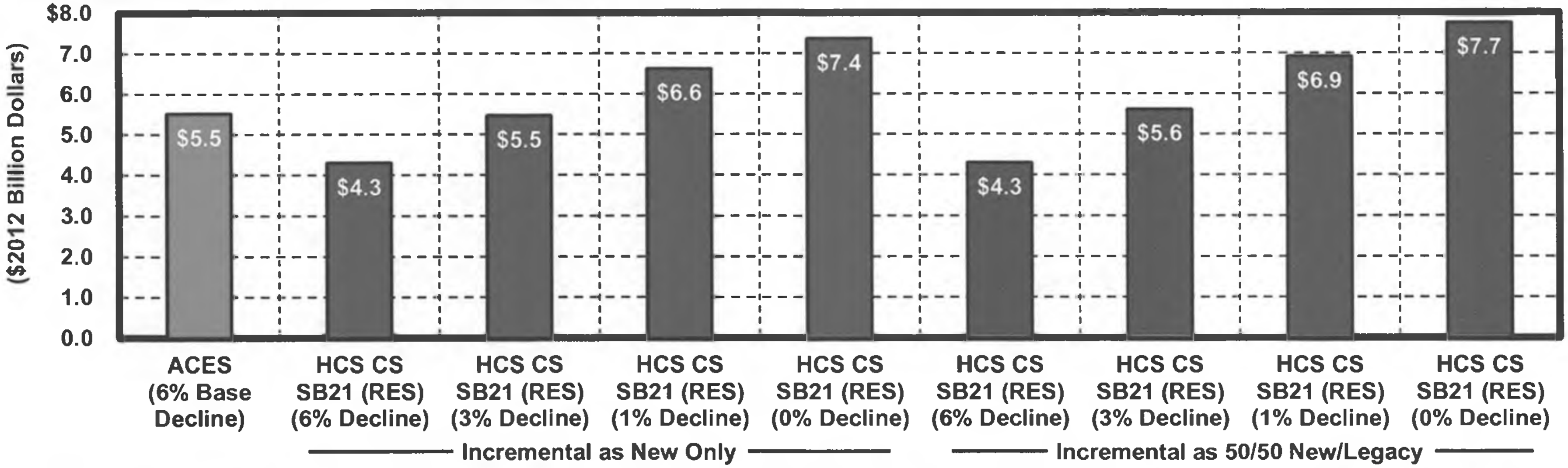
Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (~~RES~~ FIN) Alternative (35% Base Rate, 30% GRE) $120 West Coast ANS ($2012)

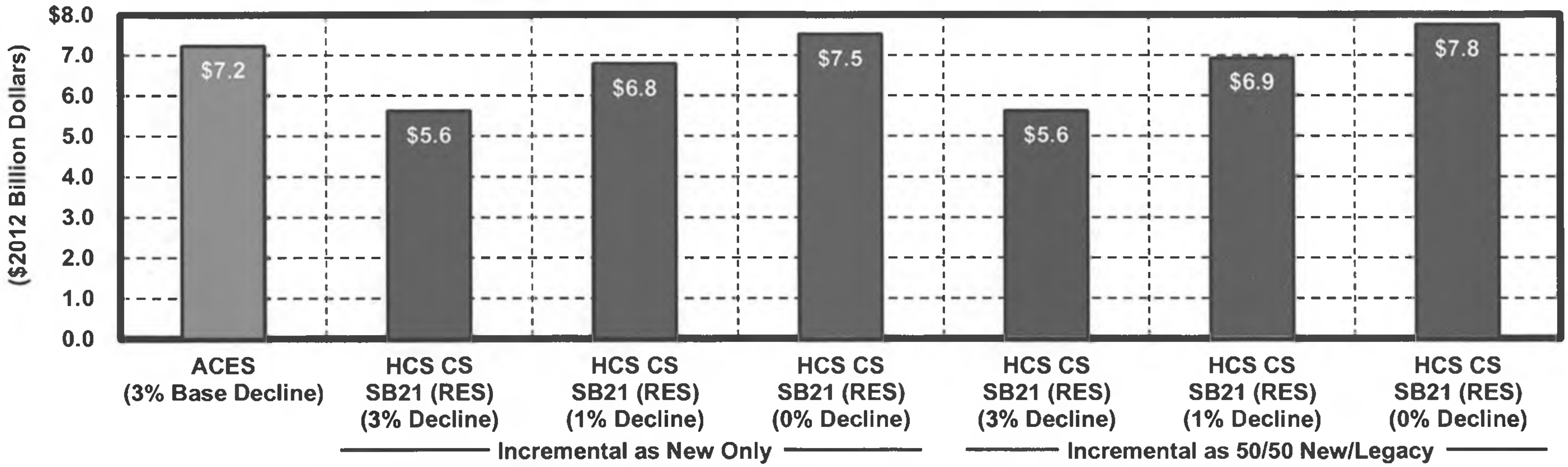




Note: Volumes over base classified as "new" assumed to qualify for GRE and carry 1/6th royalty; volumes over base classified as "legacy" assumed in PBU/KPU fields.

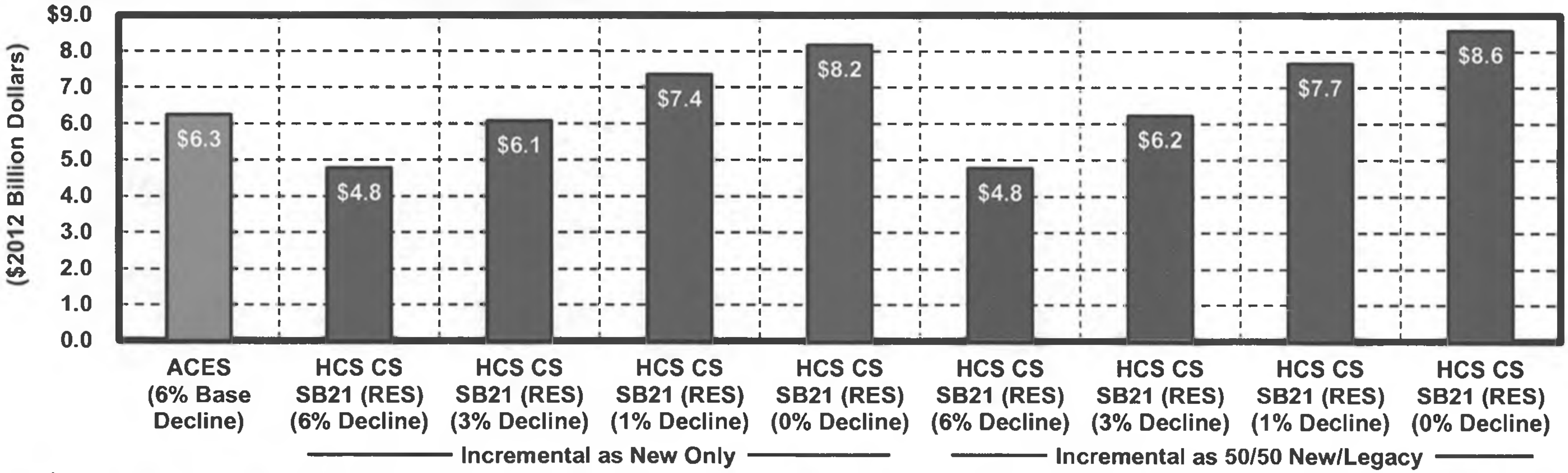
Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (RES) Alternative (35% Base Rate, 30% GRE) $130 West Coast ANS ($2012)

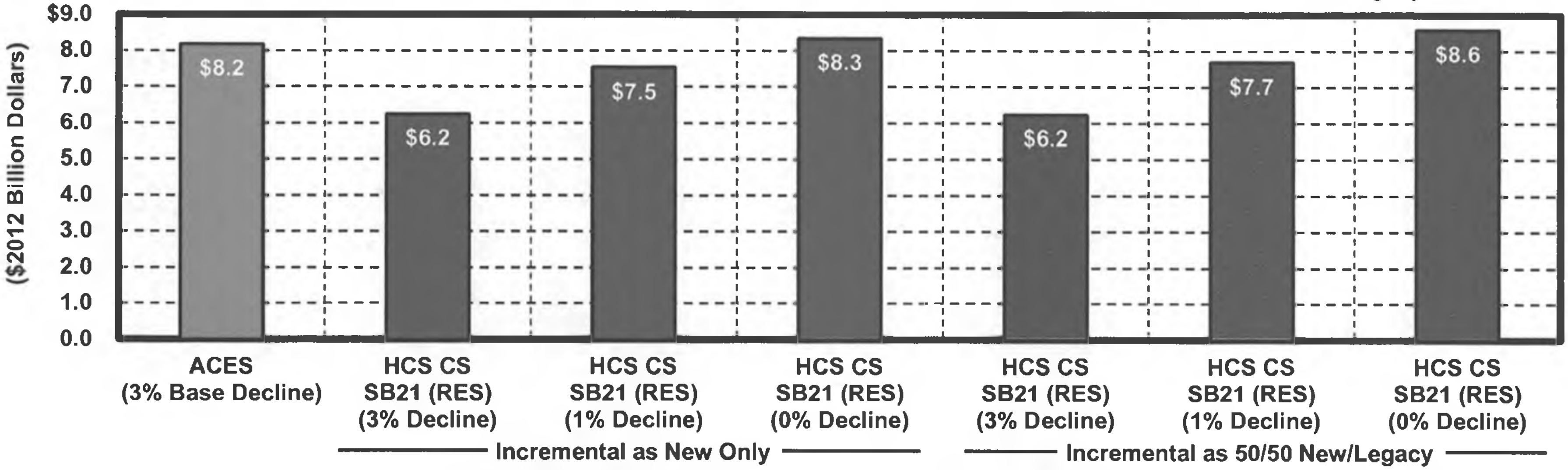




Note: Volumes over base classified as "new" assumed to qualify for GRE and carry 1/6th royalty; volumes over base classified as "legacy" assumed in PBU/KPU fields.

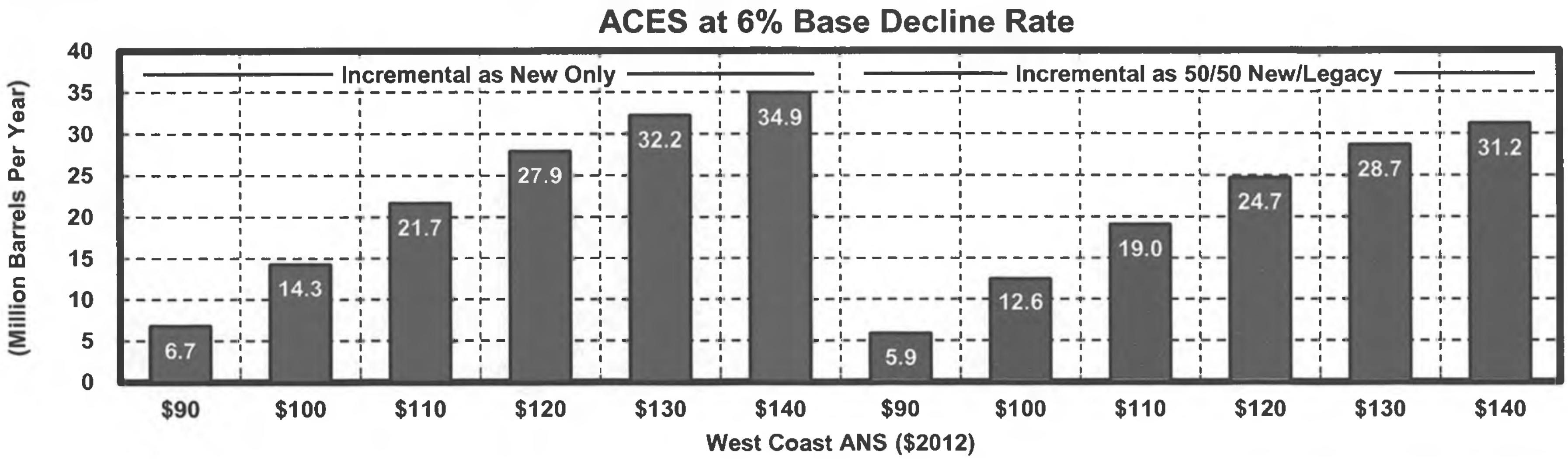
Estimated Average 2013 - 2042 State Oil Revenues ($2012 Billion Dollars) Under Potential Production and Tax Scenarios ACES v. HCS CS SB21 (RES) Alternative (35% Base Rate, 30% GRE) $140 West Coast ANS ($2012)

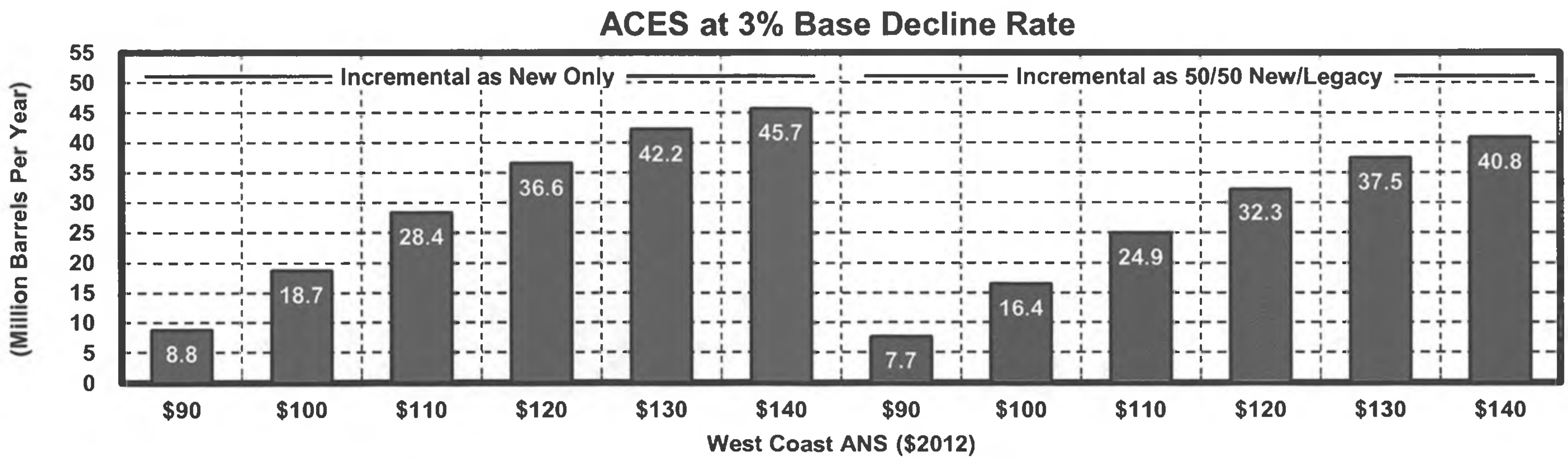




Note: Volumes over base classified as "new" assumed to qualify for GRE and carry 1/6th royalty; volumes over base classified as "legacy" assumed in PBU/KPU fields.

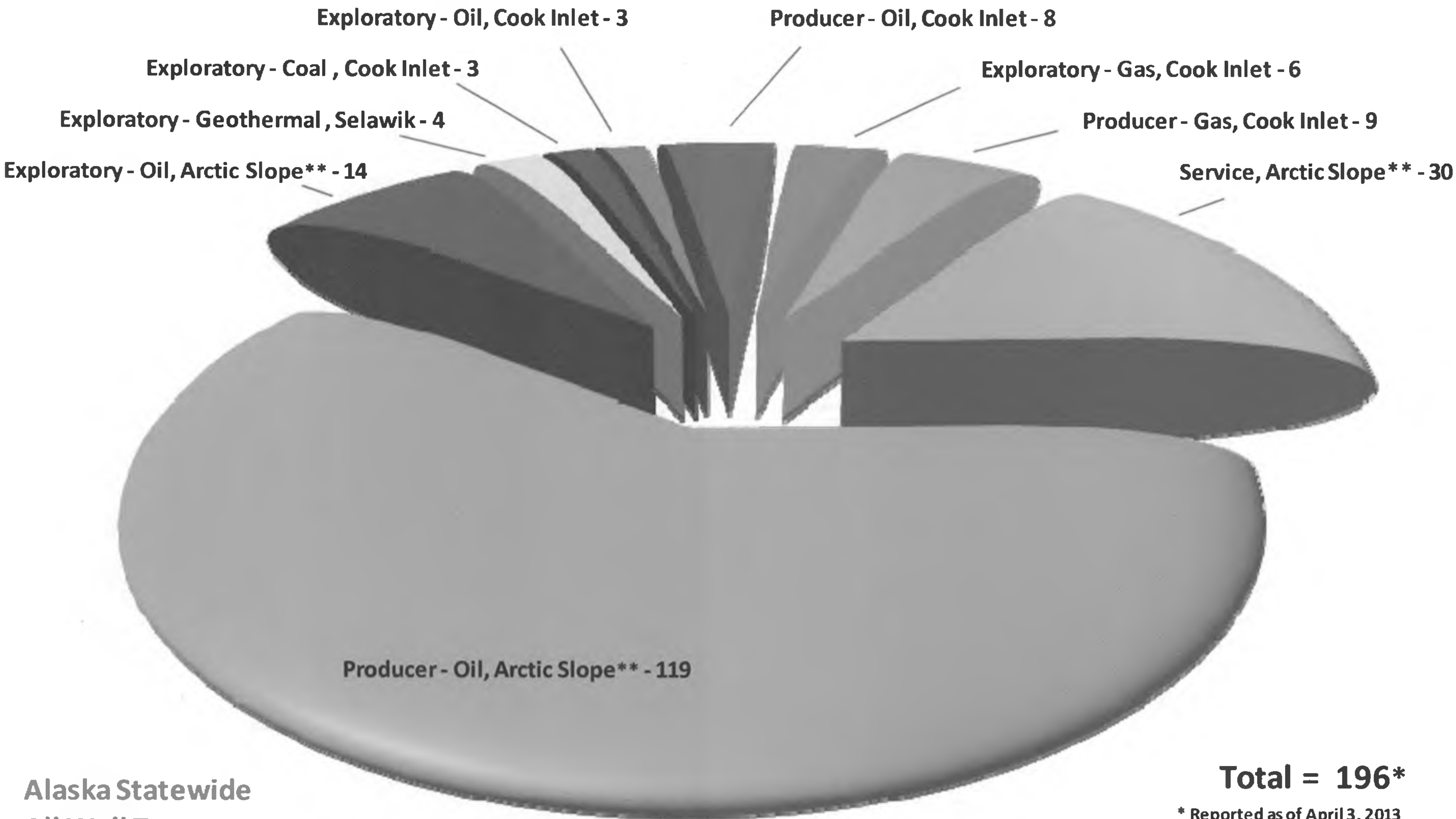
Estimated Additional Annual Volumes Needed (2013 - 2042) Under HCS CS SB21 (RES) Alternative (35% Base Rate, 30% GRE) to Match State Oil Revenues ($2012 Billion Dollars) Under ACES at 6% and 3% Decline Rates





Note: Volumes over base classified as "new" assumed to qualify for GRE and carry 1/6th royalty; volumes over base classified as "legacy" assumed in PBU/KPU fields.

Alaska 2012: Permits to Drill Approved by AOGCC



Alaska Statewide
All Well Types

Total = 196*

* Reported as of April 3, 2013

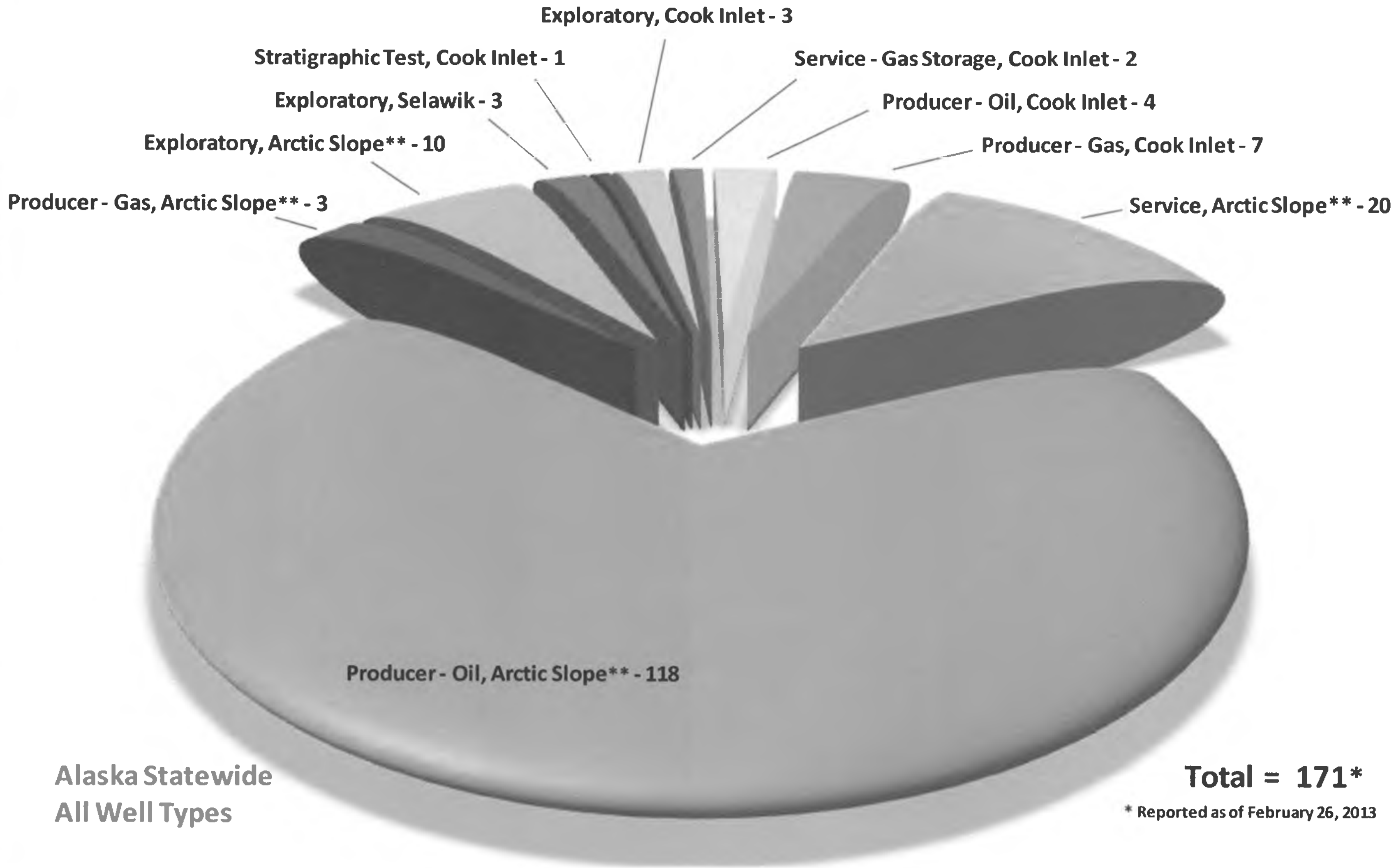
** Arctic Slope totals include wells and wellbores on state and private lands and in state waters within the Beaufort Sea

AOGCC

Count of all Permits to Drill Approved by the AOGCC during 2012

April 4, 2013

Alaska 2012: Drilled Wells and Wellbores



Alaska Statewide
All Well Types

Total = 171*

* Reported as of February 26, 2013

** Arctic Slope totals include wells and wellbores on state and private lands and in state waters within the Beaufort Sea

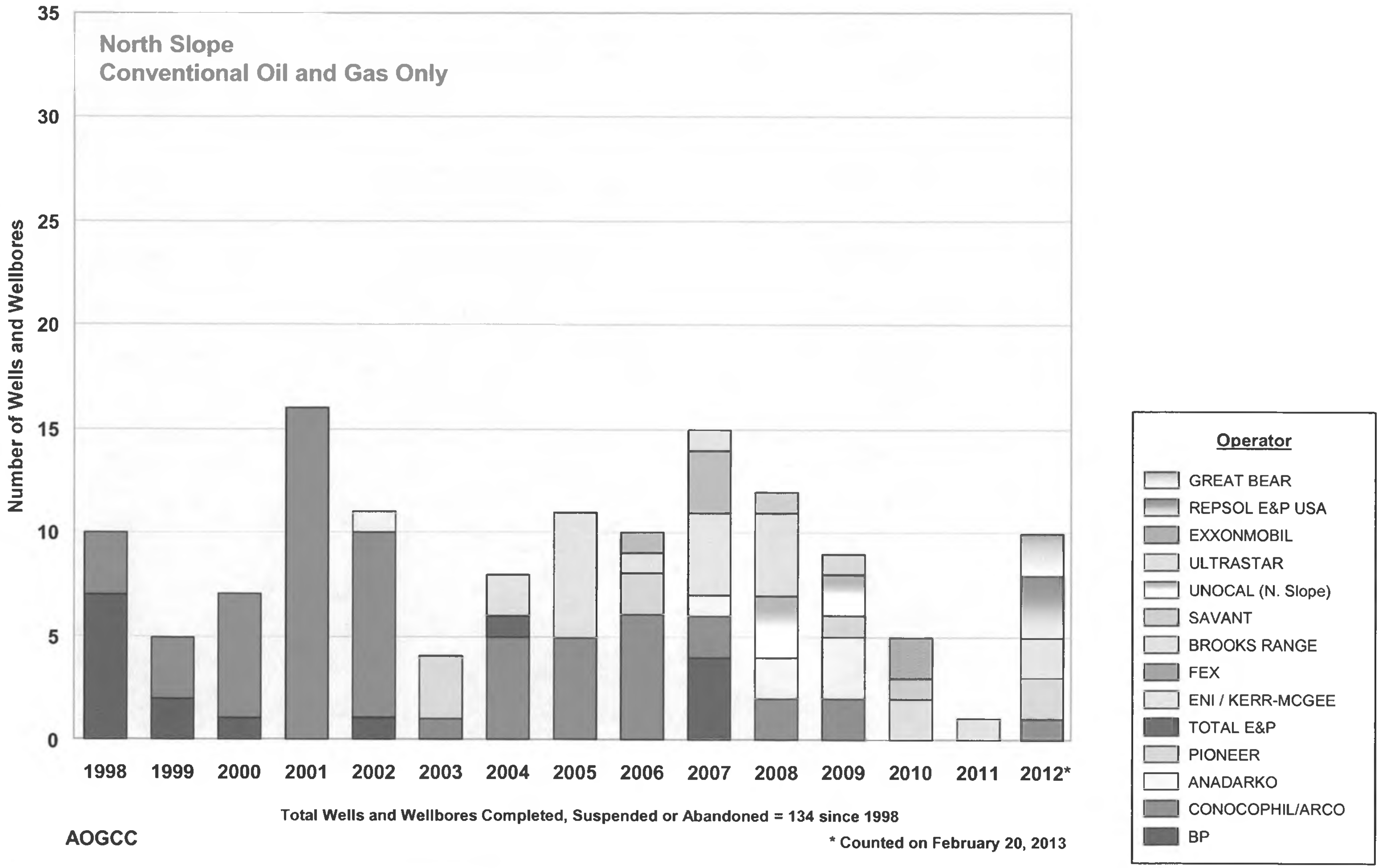
Count of all wells and wellbores completed, suspended, or plugged and abandoned during 2012

AOGCC

February 27, 2013

EXPLORATORY (WILDCAT / DELINEATION) WELLS AND WELLBORES

North Slope Oil and Gas: Completed, Suspended or Abandoned (1998 – 2012*)



Total Wells and Wellbores Completed, Suspended or Abandoned = 134 since 1998

AOGCC

* Counted on February 20, 2013

Exploratory Wells and Wellbores Drilled (1998 – 2012*)

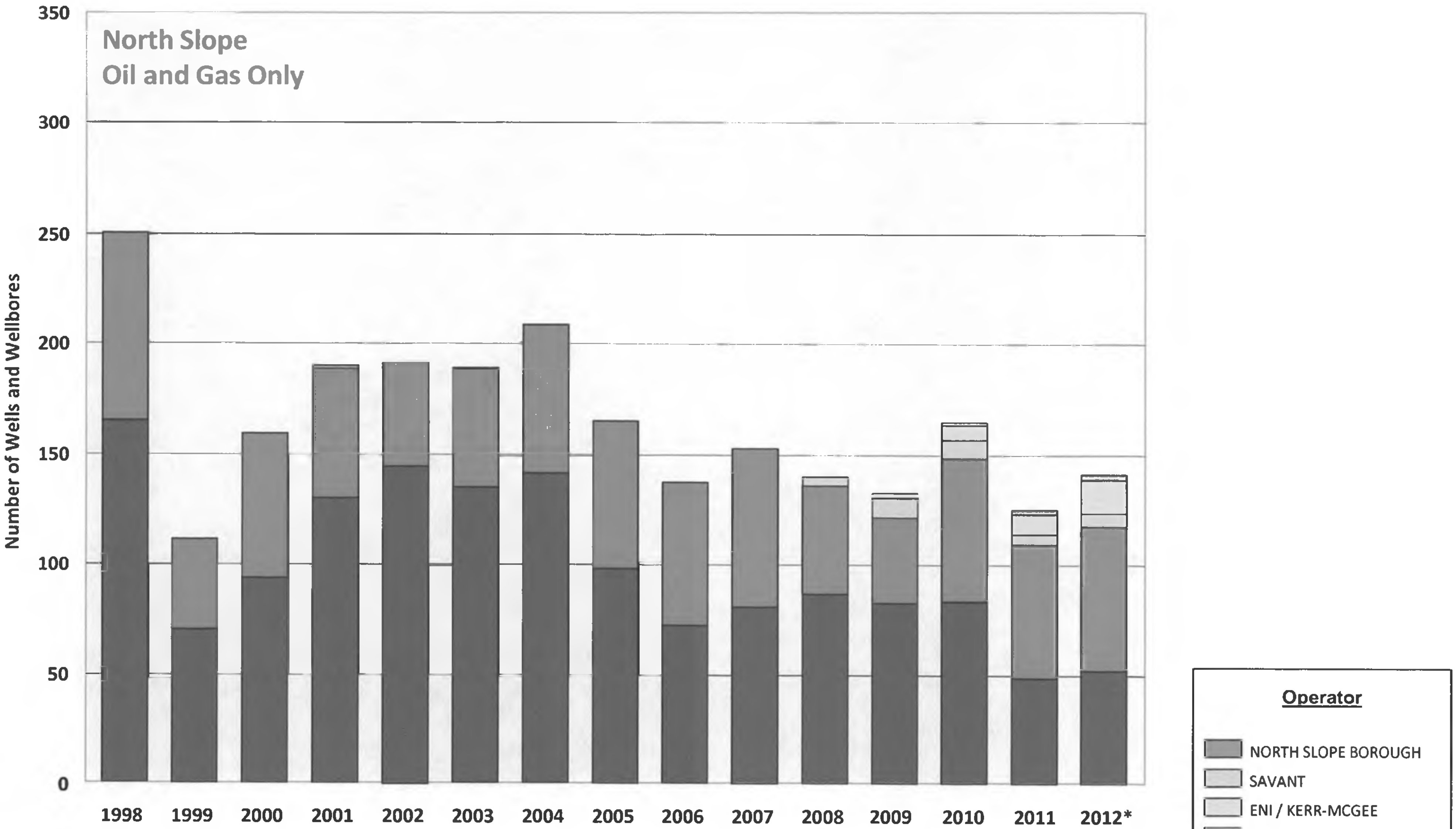
North Slope: Conventional Oil and Gas Only**

North Slope: Conventional Oil and Gas Only																
Operator	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Great Bear															2	2
Repsol															3	3
Ultrastar												1				1
ExxonMobil													2			2
Savant											1		1			2
Brooks Range										1	4		2	1	2	10
Unocal (North Slope)											3	2				5
FEX									1	3						4
Eni / Kerr-McGee							2	6	1	4						13
Total E&P							1									1
Pioneer						3			2			1			2	8
Anadarko					1					1	2	3				7
ConocoPhillips / ARCO	3	3	6	16	9	1	5	5	6	2	2	2			1	61
BP	7	2	1		1					4						15
Yearly Totals for Conventional Oil and Gas Permits	10	5	7	16	11	4	8	11	10	15	12	9	5	1	10	134

Total Wells and Wellbores Completed, Suspended or Abandoned = 134 since 1998

**Does not include coal- or shale-bed gas or gas hydrate wells

Development & Service Wells and Wellbores Drilled (1998 – 2012*)
North Slope: Conventional Oil and Gas Only**



Total Wells and Wellbores Completed, Suspended or Abandoned = 2,456 since 1998

**Does not include coal- or shale-bed gas, underground coal gasification, or geothermal

AOGCC

*** Counted on February 15, 2013**

Development & Service Wells and Wellbores Drilled (1998 – 2012*)

North Slope: Conventional Oil and Gas Only**

Development & Service Wells/Wellbores Completed, Suspended or Abandoned (1998 – 2012)

North Slope: Conventional Oil and Gas Only

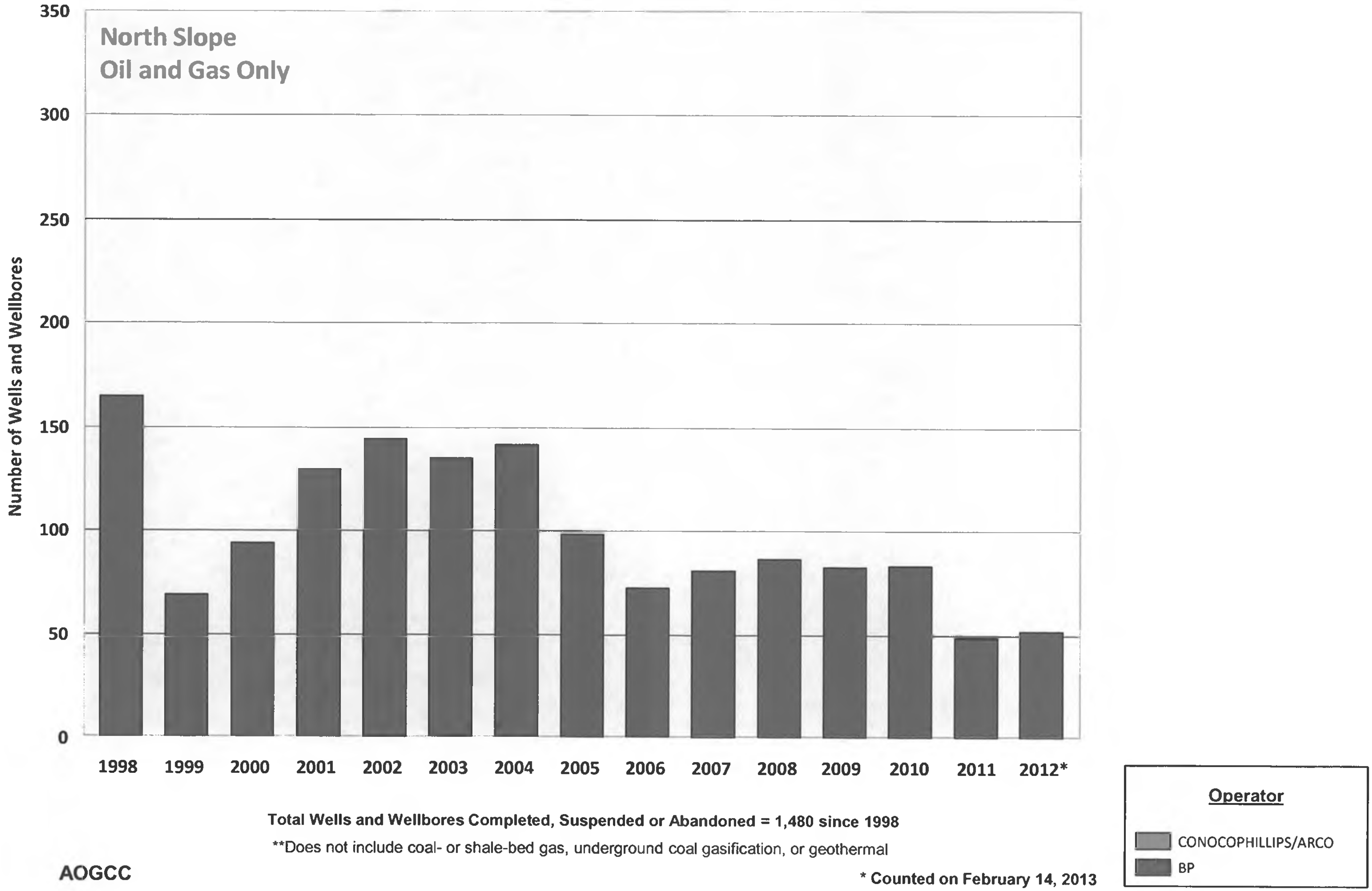
Operator	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
North Slope Borough														2	3	5
ExxonMobil				1												1
Savant													1			1
Eni / Kerr-McGee												2	7	9	15	33
Pioneer											4	9	8	5	6	32
ConocoPhillips / ARCO	86	41	66	59	47	54	67	67	65	72	49	39	65	61	66	904
BP	165	69	94	130	145	135	141	98	72	81	86	82	83	48	51	1,480
Yearly Totals for Conventional Oil and Gas Permits	251	110	160	190	192	189	208	165	137	153	139	132	164	125	141	2,456

Total Wells and Wellbores Completed, Suspended or Abandoned = 2,456 since 1998

**Does not include coal- or shale-bed gas, underground coal gasification, or geothermal

* Counted on February 15, 2013

Development & Service Wells and Wellbores Drilled (1998 – 2012*)
North Slope: Oil and Gas Only**
by BP Exploration (Alaska), Inc.



Total Wells and Wellbores Completed, Suspended or Abandoned = 1,480 since 1998

**Does not include coal- or shale-bed gas, underground coal gasification, or geothermal

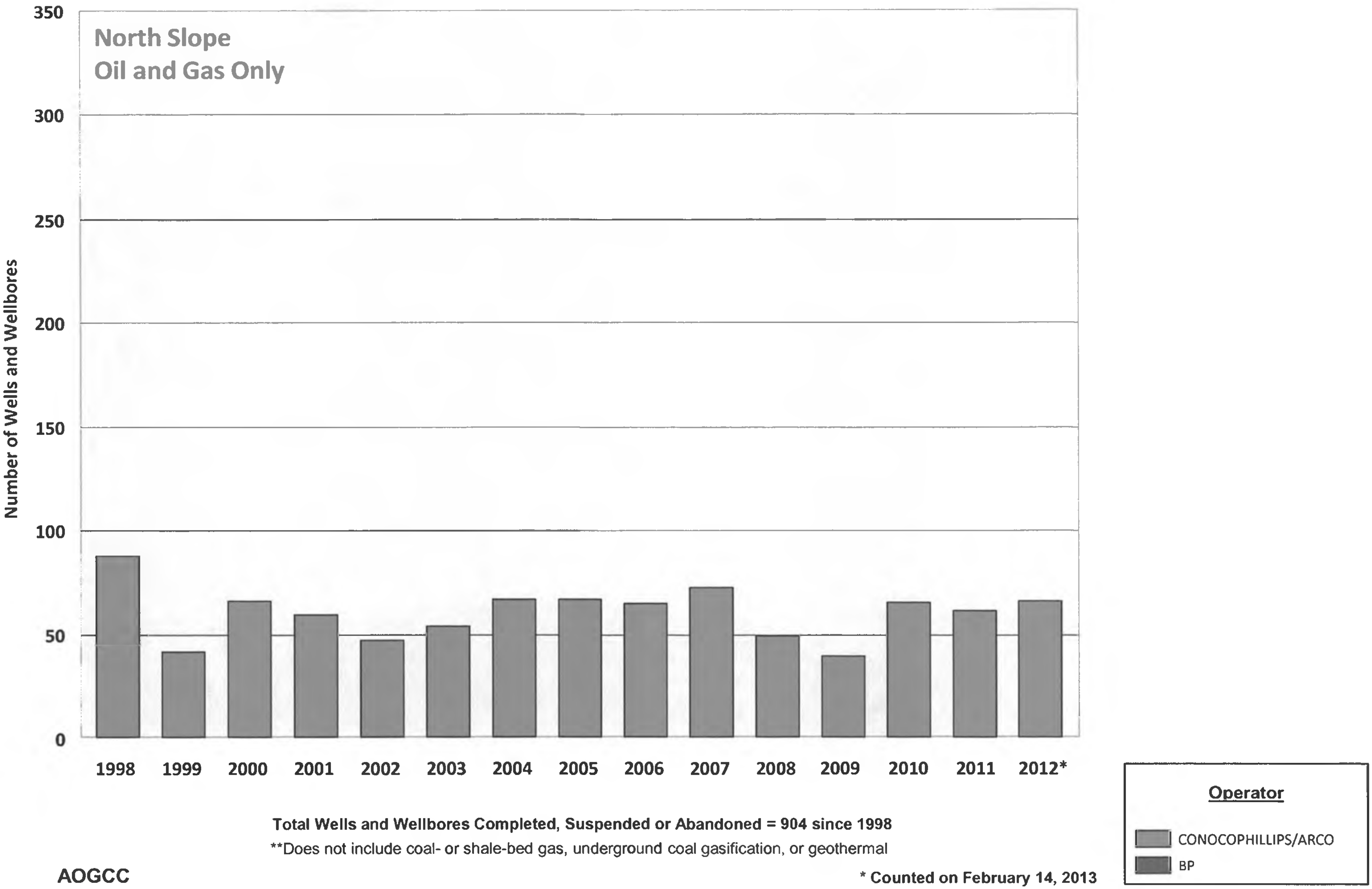
AOGCC

*** Counted on February 14, 2013**

Development & Service Wells and Wellbores Drilled (1998 – 2012*)

North Slope: Oil and Gas Only**

by ConocoPhillips Alaska, Inc.



Total Wells and Wellbores Completed, Suspended or Abandoned = 904 since 1998

**Does not include coal- or shale-bed gas, underground coal gasification, or geothermal

AOGCC

* Counted on February 14, 2013

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2007

DISTRIBUTED BY REP. GARA SB 21

Figure 4-6. Basic Data Used for ANS Oil & Gas Production Taxes

	FY 2007 History	FY 2008 Forecast	FY 2009 Forecast
State Production Tax Revenue from the North Slope			
Millions of Dollars	2,286.3	3,398.0	2,195.0
Key North Slope Assumptions			
Price of ANS WC in dollars per barrel	61.63	72.64	66.32
Transit Costs & Other in dollars per barrel	5.96	6.34	6.80
ANS Wellhead in dollars per barrel	55.67	66.30	59.32
Production in barrels per day	739,702	730,942	700,686
Royalty barrels per day	92,463	91,368	87,586
Taxable barrels per day	647,239	639,574	613,100
Lease Expenditures in Millions of Dollars			
Operating Expenditures [OPEX]	2,081	2,149	2,354
Capital Expenditures [CAPEX]	1,578	2,188	2,002
Total Expenditures	3,659	4,337	4,356
Implied North Slope Data			
Credits from CAPEX in Millions of dollars	315.6	219.0	418.9
Lease Expenditures per barrel of oil produced			
OPEX	7.71	8.05	9.21
CAPEX	5.84	8.20	7.83
Total Expenditures	13.55	16.25	17.03
Average Production Value per Barrel [Pre-Tax]	42.12	50.05	42.49
Production Tax Collected per Taxable Barrel	9.68	14.56	9.81

Notes

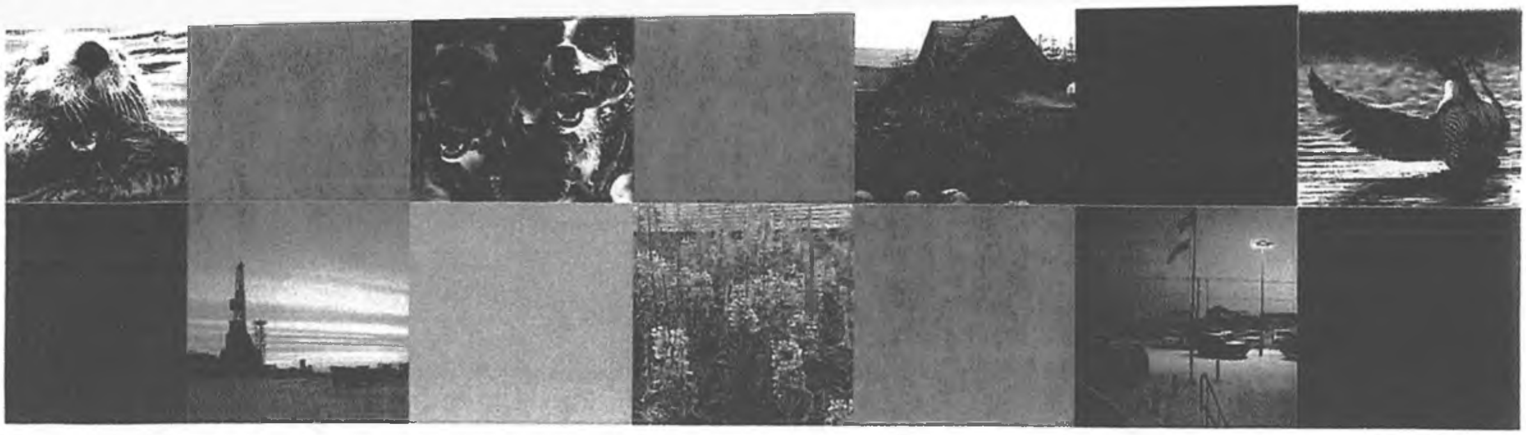
1 Costs for FY 2007 are unaudited and for the entire North Slope. Cost data reported July 2006 through December 2006 are actuals. January 2007 through June 2007 are estimates

2 Costs for FY 2008 and FY 2009 are estimated after having reviewed the annual filings from oil companies and incorporating adjustments based on our assessment of future cost increases.

3 Assumptions for the transitional credits and the $12 million credits are not included in the table.

4 The average production value per barrel presented in this table would differ from estimates the oil companies would prepare for tax liability purposes for several reasons: [a] the data in the chart are North Slope wide averages; [b] different companies have different cost structures and operate in different fields; [c] a company computing this average for tax liability purposes would only include the barrels it gets to keep, i.e., the company would exclude the barrels it pays in royalty.

5 FY 2008 ANS West Coast price forecast is as of November 30, 2007.



Revenue Sources Book

Fall 2012

Alaska Department of Revenue – Tax Division

Figure 4-7. Basic Data Used for ANS Oil & Gas Production Taxes(1)

	History	Forecast	
	FY 2012	FY 2013	FY 2014
North Slope Price and Production			
Price of ANS WC in dollars per barrel	112.65	108.67	109.61
Transit Costs & Other in dollars per barrel	8.81	9.43	8.81
ANS Wellhead in dollars per barrel	103.84	99.24	100.80
Total ANS Production in thousands of barrels per day	579.1	552.8	538.4
Royalty and federal thousands of barrels per day (2)	76.4	71.4	70.7
Taxable thousands of barrels per day	502.7	481.4	467.7
North Slope Lease Expenditures(3)(4)			
Total North Slope Lease Expenditures in $ millions			
Operating Expenditures [OPEX]	3,001.2	3,078.9	2,817.4
Capital Expenditures [CAPEX]	2,383.4	3,262.9	3,845.1
Total North Slope Expenditures	5,384.6	6,341.8	6,662.5
Deductible North Slope Lease Expenditures in $ millions			
Operating Expenditures [OPEX]	2,862.2	2,832.8	2,779.0
Capital Expenditures [CAPEX]	1,543.0	2,393.0	3,338.6
Deductible North Slope Expenditures	4,405.3	5,225.8	6,117.6
State Production Tax Revenue (1)			
Millions of Dollars	6,146.1	4,353.2	3,778.8
Production Tax Collected per Taxable Barrel	33.4	24.8	22.1
State Wide Production Tax Credits (3)(5)			
Credits Used against Tax Liability in $ millions	360.0	490.0	615.0
Credits for Potential Purchase in $ millions	353.0	360.0	400.0

(1) Production tax is calculated on a company specific basis, therefore the aggregated data reported here will not generate the total tax revenue shown. For an illustration of the tax calculation, see Appendix D.

(2) Royalty and Federal barrels represents DOR's best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, and barrels produced from federal offshore property.

(3) Lease expenditures and credits used against tax liability for FY 2012 were prepared using unaudited company-reported estimates.

(4) Expenditure data for FY 2013 and FY 2014 are compiled from company submitted expenditure forecast estimates and other documentation as provided to the DOR. Expenditures shown here are shown in two ways: (1) total estimated expenditures including for those companies with no tax liability; and (2) estimated deductible expenditures for only those companies with a tax liability.

(5) Production tax credits shown include all production tax credits and all areas of the state. North Slope CAPEX credits are spread out over two years as specified in the ACES production tax. Assumptions for the $12 million credits for small Alaska producers are included in the table.

Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal SB 21

Barry Pulliam
Managing Director
Econ One Research, Inc.

February 13, 2013

Econ One: Who We Are

- Economic Research and Consulting Firm
  - Provides Economic Analysis In Energy and Other Industries
- Advised the State of Alaska on Petroleum Related Matters For Over Two Decades
- Worked With the Cowper, Hickel, Knowles, Murkowski, Palin, and Parnell Administrations
- Assisted the Legislature Between 2005 and 2008 on Tax and Gas Development Issues
- Energy-Related Work Outside Alaska
  - State Governments: Texas, Louisiana, New Mexico, Oklahoma, California
  - Federal Government Agencies: Department of Interior, Federal Trade Commission
  - Energy Companies: Producers, Refiners, Mid-Stream Services, Pipelines, Chemicals

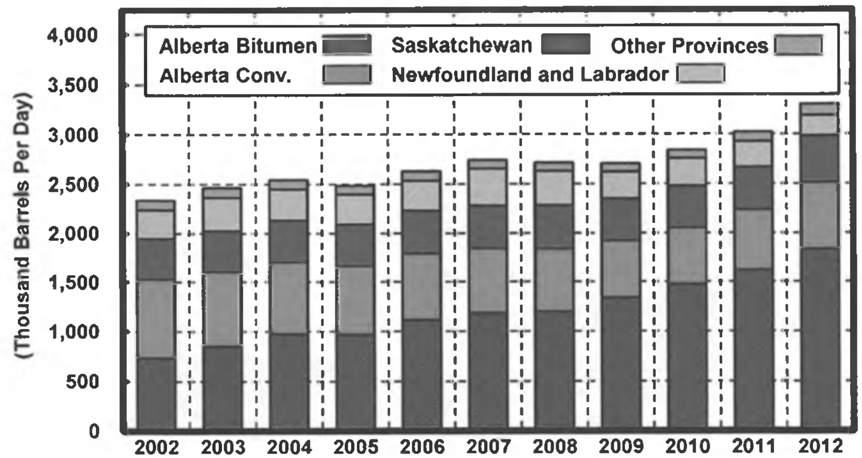
Benchmarking North Slope Activity Over The Past Decade Against Other Areas

Benchmarking

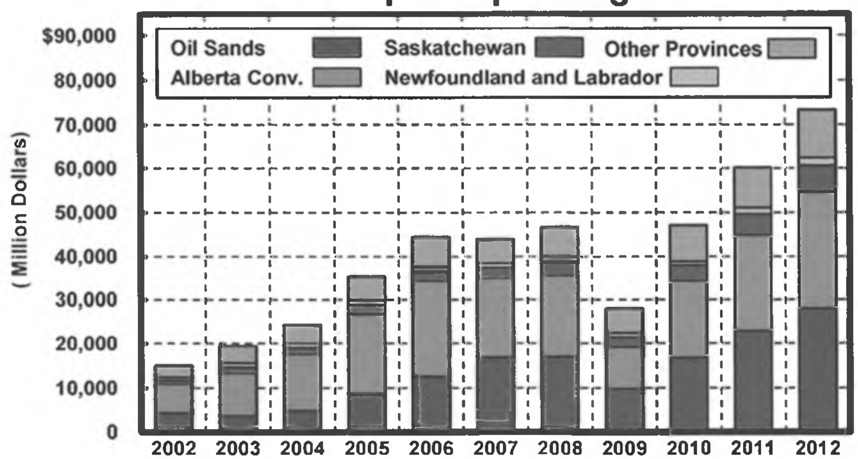
- Benchmarking Allows Us to Evaluate Activity in Alaska by Controlling for Significant Variables That are Common to All Oil Producing Properties
- No Two Producing Areas are Exactly Alike. We Attempt to Choose Locations That Share a Number of Similar Characteristics, Allowing for the Most Meaningful Comparisons
- We Benchmark the North Slope Against Significant Producing Areas in OECD Countries
  - The North Sea
  - The U.S. and Several Key Producing States / Areas
  - Canada and Producing Provinces
  - Australia
- All of These OECD Areas Have Many Characteristics in Common With North Slope
  - Similar Political and Legal Structure / Risk
  - Significant Prospectivity
  - But, Much of the "Low-Hanging" Fruit Has Been Produced
  - Development of Remaining Resources are Largely High-Cost, Either Conventional or Unconventional
  - Resources are Developed in Large Part by the Private Sector

Country/Area Profile
Canada

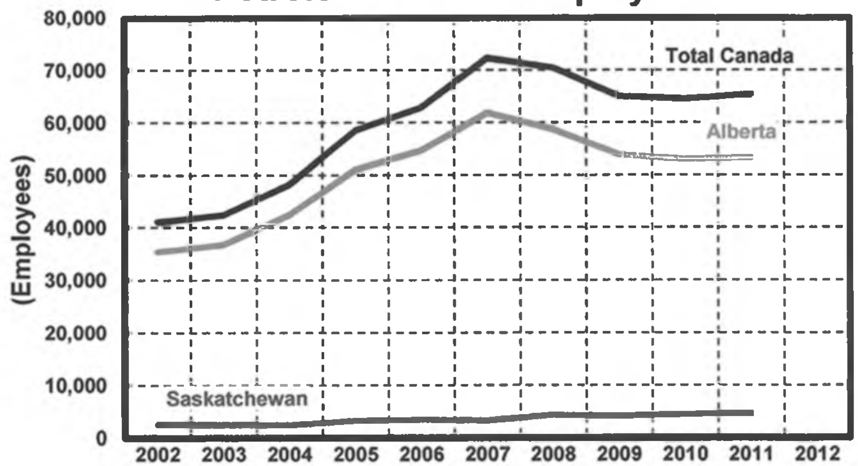
Crude Oil Production



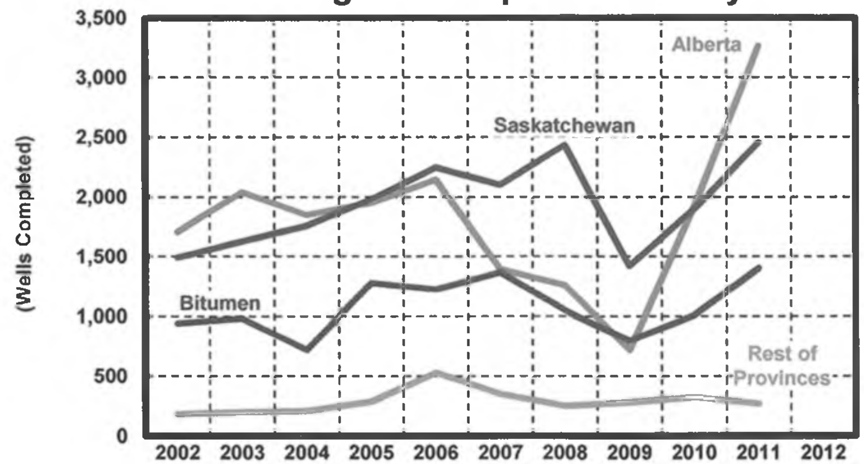
Capital Spending



Petroleum Sector Employment



Drilling / Development Activity



Note: 2012 figures are preliminary.

THOMSON REUTERS STREETEVENTS

EDITED TRANSCRIPT

COP - ConocoPhillips Analyst Meeting

EVENT DATE/TIME: FEBRUARY 28, 2013 / 01:30PM GMT

CORPORATE PARTICIPANTS

Ellen DeSanctis *ConocoPhillips - VP - IR & Communications*

Ryan Lance *ConocoPhillips - Chairman, CEO*

Matthew Fox *ConocoPhillips - EVP - Exploration & Production*

Alan Hirshberg *ConocoPhillips - EVP - Technology and Projects*

Jeffrey Sheets *ConocoPhillips - EVP - Finance, CFO*

Vladimir dela Cruz *ConocoPhillips - Director, Investor Relations*

CONFERENCE CALL PARTICIPANTS

Doug Leggate *Bank of America/Merrill Lynch - Analyst*

Paul Sankey *Deutsche Bank - Analyst*

Gary Low *Epoch - Analyst*

Edward Westlake *Credit Suisse - Analyst*

Iain Reid *Jefferies & Company, Inc. - Analyst*

Jason Gammel *Macquarie - Analyst*

Paul Cheng *Barclays Capital - Analyst*

Blake Fernandez *Howard Weil - Analyst*

Robert Kessler *Tudor, Pickering, Holt & Co. - Analyst*

John Herrlin *Societe Generale - Analyst*

Evan Calio *Morgan Stanley - Analyst*

Roger Read *Wells Fargo - Analyst*

Faisel Khan *Citigroup - Analyst*

Scott Hanold *RBC Capital Market - Analyst*

Boris Raykin *Granite Associates - Analyst*

Doug Terreson *ISI Group - Analyst*

PRESENTATION

Ellen DeSanctis - *ConocoPhillips - VP - IR & Communications*

Good morning everybody and welcome. My name is Ellen DeSanctis and I'm the vice president of investor relations and communications for ConocoPhillips. For those of you in the room, thank you so much for being here today. And for our listeners on the phone, thank you for your participation as well.

This morning you're going to hear from four of our senior executives, and let me take a moment and introduce them to you now. Ryan Lance is our chairman and CEO. Matt Fox is our exploration and production EVP. Al Hirshberg is the EVP of Technology and Projects. And Jeff Sheets is our EVP of finance and our chief financial officer.

In addition, we have some other members of our senior leadership team here this morning, and I welcome those of you in the room to introduce yourselves to them after this morning's event. And now, let me take care of a few quick but important administrative matters.

This morning's meeting will be webcast live, our materials are now available on our website. A replay and a transcript of this call will be available shortly. And then finally, I know several of you have looked ahead in the book, so you already know this. We will be making some forward-looking statements this morning.

Our future performance could differ materially from the expectations we share today. The risk and uncertainties in that performance, we've outlined in this cautionary statement shown here as well as in our periodic filings with the SEC. The most recent of which, it was our 10-K filed on February 19th. And now, it is my sincere privilege to invite Ryan Lance to begin the meeting.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Well, thank you and good morning everyone. It's my pleasure to also welcome you to ConocoPhillips' first investor analyst meeting as an independent company. You'll notice the title of the slide, it's unchanged since we launched this company in May of last year.

We do think we represent a new class of investment for investors and we're looking forward to sharing our plans with you today.

Our whole organization is fully committed to organically growing and creating value for ConocoPhillips. I'll tell you myself, my entire leadership team and 16,900 employees, all of us are all aligned with getting this done.

So what does a new class of investment mean? It means that our goal is to consistently deliver stable and predictable returns to our shareholders. We're going to do that through a very diverse and global asset base real strong technical capability, a committed workforce in financial strength. So it is about organically growing this company, growing the production, growing the margins, growing the cash flows and growing the returns. And we're off to a great start in 2012 or had a great start in 2012.

And let me just share a little bit about what our performance was for last year. Certainly, the strategic highlight of the year was completing the separation of our downstream business. So ConocoPhillips emerged as an E&P company completely and totally focus on this side of the business.

We're executing our plans. We're running well. We announced dispositions to core up the portfolio and help fund our growth programs. We met our volume targets for the year with some notable achievements, 100,000 barrels a day out of our Eagle Ford area and growing, 100,000 barrels a day out of our oil sands position and growing and our first production out of our large Gumusut field in Malaysia.

We delivered 156% reserve replacement which for company our size is a pretty considerable achievement. And the business is running well. Our growth programs are on track, our projects are on track and we're building momentum on the exploration side, both unconventionally and conventionally.

Now, 2013 and 2014 are important years on the exploration side. We got to put runs on the board, but we're off to a really good start. I'm not going to steal Matt's thunder because I'm going to let him tell you about some of the success we've had on the exploration site already.

Financially, we've maintained a strong balance sheet, our A credit rating. We funded almost $8.5 billion to shareholders this last year through share buyback and dividends. And certainly, we got a strong shareholder return, and that's shown here on this next slide.

So you look at our performance in 2012 and the shareholders were well rewarded. We outperformed the peer group and we outperformed the S&P 500. So we are off to a great start. But we understand that it's the end of the February. The clock is ticking and it is about what are we doing in 2013 and what are we doing to deliver on those plans. So we're going to spend the rest of our time talking about what our plans look like going forward.

So we started '13 in a great position as a company, globally diverse a great set of assets. We're the largest North American-based independent company. 1.5 million barrels a day of production. 8.6 billion barrels of reserves. 80% of those reserves are located in OECD countries giving our portfolio a lower risk feels relative to the competition.

We've got another incredible attributes around the portfolio, large legacy positions around the world considerable number of development programs in around those legacy positions to keep our production flat over the timeframe that we'll talk about.

That inventory of high quality development projects, they're adding top line growth and high margins to our production and our financials. And we're positioned around the world in many of the key areas. We have significant technical capability. We have a strong balance sheet and financial flexibility in an ongoing commitment to our shareholders.

But we are in an environment where executing this business. Prices are relatively high today, but uncertain futures. And this shows the range of uncertainty around the forward look on commodity prices. But my crystal ball isn't any clearer than many of you in this room today. And the range of this, whether you're on the high-end or the low-end is subject of what you think supply and demand is going to do and some of the geopolitical factors that impact that. And we know that we're seeing local and regional dislocations in some of the prices, like WCS or netbacks to bitumen in Canadian Oil Sands and North American NGL prices.

What I will say is when we develop our plans, we're typically on the low-end of these ranges as we think about our long-term plans that we're trying to execute in the Company. We see that we run scenarios now and we think about the business factors, that cost environment and the regulatory environment that we're in and we make sure our plans are resilient at the top end and the low-end of these ranges. One other important point, the margin analysis that you're going to see today is a big part of our value proposition. It's based on real prices of Brent at $100, WTI at $90, WCS at $70, and $3.50 Henry Hub.

But against that uncertain future world, we think we're well-positioned as a company. We do believe that our diversification, our size and our scale are a competitive advantage. We're not reliant on one product, one geography, on geology to succeed as a company. And we think that's an important competitive advantage in this business today. We're focused on organically growing the Company. We're going to make our investments in high quality development programs in and around our legacy assets.

We're going to execute major project programs and deliver top-end growth through our production and our very high-margin when they come in. We'll apply our significant technical capability. We'll maintain our financial flexibility. And we're also looking to rebalance the portfolio a little bit. So we've talked about divestitures to core up the portfolio. We're also looking at trying to rebalance overtime.

The reason we're doing this is to try to drive the portfolio to a lower cost of supply and provide more flexibility in the portfolio. This means like large asset positions like APLNG and Oil Sands we would like to reduce our exposure to some of those areas overtime.

Now, these are great assets and great resource positions. But with our growing unconventional and deep water opportunities we would like to rebalance the portfolio overtime. We're not in a hurry. We're not going to do a bad deal. We're going to do a deal that makes sense to the Company. But I will tell you our plans today assume that we're going to lighten up in assets like APLNG and the Canadian Oil Sands over time.

But it is about creating good choices and options in this portfolio. We have a great legacy position to draw upon and we've captured a lot of great compelling opportunities for the Company. So it is about trying to balance the portfolio to the highest set of opportunities that deliver the best returns and margins for the Company.

So, that's a bit of the how we're going to go through and do this. This is the what? And that's unchanged as well from when we launched the Company in May. This is our value proposition, and it is to deliver stable predictable returns to the shareholders. We're going to do that through a relentless focus on safety and execution. We're going to run this business well. We know how to do it. It's part of our legacy. It remains a core part of what we're doing as a company.

We're going to offer a compelling dividend. We're going to offer 3% to 5% production growth, 3% to 5% margin growth with an ongoing priority for returns, not only absolute returns but returns relative to the competition. So at the end of the day, it's a dividend, it's 6% to 10% growth in production and margin delivering double digit returns. That's what we're all committed to go do and that's the value proposition we have for this new class of investment.

Now, this is how we're going to fund our capital program, where are we going to direct our capital and the kind of production that we're going to deliver. We're reaffirming what we came out in May last year and said, long term we're going to grow this company 3% to 5%. And that's off our base in 2012 that we talked about last May.

Now, we do see a bit of a dip in our production in 2013. We also talked about that in May. And that's scoring up the portfolio and selling the assets that we've announced. We expect to close those this year. But out of that based in 2013, that's pretty impressive growth for a company our size, we have clear line of sight to 1.9 million barrels a day by 2017.

And that growth is real. The growth is in execution today and is delivering high margin. So let me talk about the margin end of that story, which is the other half of the value proposition that we're offering here to the investors. So the left hand side of the slide, those are the five major growth areas that we're executing around the world today.

And you'll see relative to the portfolio today, these investments are in areas where it's a different product mix. It's mostly liquids and oil and it's in geographies or areas that have a lower effective tax rate relative to our base portfolio. And that delivers the margins that are shown on the right hand side of the chart.

So it isn't about just growing production. It's about growing high margin production. And Matt and Jeff are both going to come up and talk about the opportunities and details and clarity around where this growth is coming from and where this margin is coming from. So it's clear what we're doing, how we're going to deliver it and where it's coming from.

Now as I think about our cash flows, we think about the priorities for that cash and the dividend remains the top priority in our business. It underpins our performance and provides predictable returns to our shareholders. And our commitment is that we will grow that overtime modestly as our cash flows grow. And I've seen it. It does enhance capital discipline in the Company. It does work. And it remains our top priority.

Next, we'll invest in a capital program that has deep and rich inventory of opportunities both in or around of our legacy assets and grow the Company and an exploration program to continue that growth and development well beyond the timeframe that we'll talk about today. The balance sheet is important. It's an asset in company just like any other asset that we're developing, so we're going to maintain that strength and provide us flexibility through the cycles.

And we'll consider share repurchases. We'll do that when the environment provides that opportunity and provided it competes against the investments that we have in our portfolio today. So what are you going to hear today? So Matt is going to come up. He's going to talk about our base in the legacy assets that we have around the world.

What we're doing to enhance and maintain and defend the base production we have around the world today. He's going to talk about a rich and a deep inventory of development programs in and around those legacy assets that keep our production flat. The major projects that are in execution for top line growth and high margin opportunities for the Company and the upside that we're experiencing and building out of our exploration program both unconventionally and conventionally.

Al is also going to come up. He's going to talk about how we're using technology and innovation to drive greater performance out of our base, our projects, our development programs and help our exploration organization get access to rich opportunities around the world.

And then finally, Jeff is going to come up and he's going to talk about the margins. He's going to talk about the growth. It's real, it's in execution where we're making our investments and how we're driving and increasing our cash flows so we can fully fund this capital program that I talked about in the dividends.

So with that, that completes my opening comments. I'll come back later and close it up and take questions. But I'd like to turn it over to Matt and he's going to talk about the base portfolio, where we're making the investments and driving the margin in this business.

Matthew Fox - ***ConocoPhillips - EVP - Exploration & Production***

Thank you, Ryan. Good morning everyone. So what I'm going to do this morning is build upon Ryan's opening remarks and talk about our five-year plan in some detail. And my objective is to give clarity and confidence in our ability to grow our production and our margins by 3% to 5% a year over the next five years and give you some line of sight into what's coming after those five years from an exploration program.

So let's get started. This is a slide that Ryan just showed. And I'm showing it because if my boss likes, I like it. But I'm also showing it because if you look at the capital allocation strategy that's represented in the left hand side of this chart, this is really what drives our future production growth, our margin growth and our growing returns.

And my presentation is designed to work through this capital allocation strategy and give you a clearer line of sight into the details of where the growth is coming from. So we intend to spend about $16 billion a year over the next five years. We're going to invest about 10% of that in base maintenance. So, that's capital investments to improve our operating efficiency or extend the life of our existing asset base, and most importantly, its capital investments to maintain the operating integrity of our legacy assets.

We're going to spend about 45% of our capital on what we call development programs. And what that means in our vernacular is these are really drilling-led programs and they are either drilling around our legacy production assets with very little infrastructure cost required and very low to little incremental operating cost or their drilling programs are creating new legacy assets for us in places like the Eagle Ford and the Bakken.

The production associated with those development projects mitigates base decline. In fact, it more mitigates base decline. As you can see on the right, it completely offsets base decline. So, that's a very important part of our capital investment, and I'm going to give you some detail and confidence in how these development programs will do just that.

And then we're going to spend about 30% of our capital investing in major projects around the world. So, these are typical major projects for a large E&P, major capital investments with a lot of infrastructure upfront. Some delayed gratification before production arrives. In fact, that gratification isn't really significant with the lead because that production from our major project starts to kick in at the end of this year and continues to grow all the way through, let's say, five-year period resulting in this 3% to 5% growth.

But we're not satisfied with just five years of growth. So we're investing 15% of our capital and exploration and appraisal to deliver growth beyond 2017, and I'm going to talk about that in more detail later. So, that's a high level view of where this presentation is going. And I'm going to start there by giving you some color on our base.

So the base production is the foundation upon which we build this growth, and it's very important for us as an organization to make sure that we're protecting the base properly. And we have very rigorous and systematic operations excellence programs in place that are applied across the whole company where we have knowledge sharing.

In fact, we have award-winning knowledge sharing across the whole organization to make sure that things that we learn in the North Sea can be applied in Malaysia. Things that we learn in Alaska can be applied in Australia, and so on.

Now, I often hear people say, surely the stuff that you learn in the North Sea and an offshore environment from a conventional reservoir that can't be applied to unconventional reservoir as far as in Texas. Well, absolutely, it can because it turns out that a lot of conventional wisdoms can be applied to unconventional developments and then -- you'll see that as we go through the presentation.

So, I'll give you one example, in Stavanger, Norway, we have a state of the art integrated operation center. I mean this is as good or better than anyone else has in the industry. And what is our integrated operation center or onshore does is it manages our integrated planning and optimizes our day to day production and our fields offshore in Norway.

So we've taken that, those processes, those tools and we transfer that to integrated operation center in Houston that's going to manage the operations for Eagle Ford development. And Al is was going to talk a bit more about, actually, augmenting that to customize it for an onshore environment. So that's just one example. But there are loads of examples of where these learning from parts of our portfolio can be applied to other parts of the portfolio and it's one of the strengths of the diversity that the Company has.

So the decline, I'm going to show you the decline rates for each of the major segments as we go through the presentation. The average decline rate unmitigated is about 10% a year over these five years. The mitigated decline is zero, but the underlying decline from wells that we're producing at end of 2012 is about 10% a year. It's a bit higher in our dry gas assets and it's a bit lower in our liquids rich and oil assets. But our average is 10% a year. And then the development programs completely offset that decline. So I'm going to go on and talk about the development programs.

So these development programs are going to add 600,000 barrels a day of production by 2017. Now, that's a pretty impressive production add over five years. I think you'd agree. About 250,000 barrels a day of that is going to come from what we called our legacy conventional business.

So, that's an international development around our major projects, our major assets. And I'm going to talk about those in more detail. Over 200,000 barrels a day of that comes from our three major programs in the Lower 48, the Eagle Ford, the Permian and the Bakken. I'm going to talk about them in detail. And then that is made up to 600,000 barrels a day through additional North American unconventional developments that I'll also talk about.

So I'm going to go through each of these in turn, and I'm going to start from Alaska and work clockwise around the globe to give you some detail on each of this. So starting with Alaska, and before I go into the details in Alaska I just want to clear the slide because a lot of the slides that we're going to talk about look the same as this four pack.

What you're going to see on the right hand side are some numbers how much we're going to spend in capital over the next five years, what the F&D characteristics are of that capital spend and then some factoids around what we're doing.

And the bottom right, you're going to see two bar graphs, the one on the left is our current production mix within that segment or asset base as it varies a little bit and the one on the right is the incremental characteristics of the incremental production that's coming from these development programs. That gives you a sense of what's happening to the margins associated with these development programs.

On the left, you're going to see the incremental production that comes from the programs. And on the top left, you're going to see a pretty picture or a map. Okay? So, that just clears -- you're going to see a lot of these slides. And I don't intend to talk about all the details around these slides. You guys can do that. You can read that at your leisure.

So just hitting the high points, in Alaska we have numerous development opportunities in and around our existing assets all the way from Prudhoe Bay to Kuparuk, to Alpine and the associated Satellite Fields. And what we're doing here is we're applying high technology drilling capabilities and things like coil tubing drilling, steerable liner drilling guided by Time Lapse 3D seismic are great. We call 4D seismic. And Al is going to talk more about this technology, these technologies actually in his presentation.

So, that investment results in an incremental 35,000 barrels a day by 2017, which mitigates the base decline in Alaska to about 3% a year. Now, this doesn't include the Alpine West major project, when we add Alpine West, then the base decline is mitigated to about 2% a year.

Now, there are a lot of these opportunities across our legacy asset based on the slope. For the fiscal regime in Alaska is not as competitive as it needs to be to make sure that there were opportunity are fully exploited and we know that the Alaska legislature and the governor are working on ways to improve the investment climate in Alaska. And when that's done, we can see additional opportunities that we could take advantage of to grow production in Alaska and to grow production through the Trans-Alaska Pipeline System.

So moving from Alaska now to our Western Canada business unit, we have an incredible legacy asset base in Western Canada. And what we are doing here is we're taking advantage of unconventional technology, long horizontal wells, multistage fracks to go into our legacy asset base and find new ways, essentially revitalizing this asset base using these unconventional technologies across multiple plays.

These development programs will add over 100,000 barrels a day of production by 2017 and mitigates the base decline over this period to zero decline rate. So there's a dip in 2014 and '15. And all of these projects have rates of return above 20%. We're not going to invest in them unless they do.

And what you can see and the reason their returns are high is if you look at the bottom right chart, the liquid yield from these investments is double the current liquid yield of a Canadian, Western Canada asset base. And the NGL start showing up here. These are C3 plus, methane sold in the gas stream. So these are C3 plus. So they're valuable NGL barrels.

So if I move now from Western Canada to European development programs, and here we're focused on extending and growing the value of our legacy asset base. Some of this is basic blocking and tackling, info drilling, managing water flood well. But we're also applying high technology 4D seismic and intelligent well installations to make sure we're really are getting the best of our existing assets here.

And you can see again on the bottom right that the incremental production is a better liquids mix than the base production so the margins are going to grow associated, we think that's incremental production. And that contributes about 40,000 barrels a day by 2017 and mitigates the base decline in Europe to 7%.

Now, when we add the major projects that is going on Europe, and I'm going to talk about in a few minutes. We're actually growing our European production over these five years. So let's move on from Europe now to Southeast Asia and talk about the incremental production associated with the development programs there.

Now, really, the story in our Asia Pacific Middle East region is about major projects. But for completeness I included this here because we do have incremental opportunities here that are drilling high-value gas in Indonesia, drilling infill and extension wells in Bohai Bay. The third phase of development at the Bayu-Undan field adding LNG and condensate production. And these contribute about 25,000 barrels a day by 2017, that same sort of high margin mix that we currently have in our Asia Pacific Middle East segment.

So I just want to pause for a moment here because I'm about to come back to the Lower 48 and talk about our development programs here. But what I just showed you was more than 200,000 barrels a day of production, all of which is coming at higher margins than at current base and all of it coming from around our legacy assets. And we have more opportunities like this that are emerging around all of our legacy asset positions. So it's 200,000 barrels a day of increasing margins from our legacy assets outside the Lower 48.

So now we'll move to the Lower 48 and I'm going to talk, first of all, about our Permian conventional opportunity set. I'm going to talk later about our Permian unconventional opportunities set. The Permian basin is a basin that keeps on giving. And it really is a remarkable basin and we have a million acres held by production in the Permian.

We see a lot of opportunities in our conventional assets to add high value barrels. And you can see on the bottom right here, this is essentially all oil that we're adding through these conventional programs. This investment over these five years adds 40,000 barrels a day to a conventional production and it results in a 7% compound annual growth rate and a Permian conventional.

And there are lots of additional opportunities within Permian conventional asset base, all held by production. And we will see more growth from our Permian conventional base in the years beyond this.

So let's move on now and talk about our two major development programs in the unconventional areas. I'll start first by talking about the Bakken. So we are right on the heart of the trend of the Bakken. We've got 600,000 acres in total in this area, 200,000 of it is right on top of the Nesson Anticline. And we've got 400,000 of mineral acreage also that we'll have development potential in the unconventional too.

So you can see on the bottom right, this is all oil and this is compared to existing Lower 40 average product mix. We're going to add 45,000 barrels a day by 2017 and that's an 18% compound annual growth rate from Bakken assets and there's lots of opportunities remaining here. More than 1,400 identified well locations, 600 million barrels of resources. Of those 600 million barrels of resource, we have only booked so far about 90 million barrels. That's a lot of growth remaining in our Bakken position.

Now if I move from Bakken to the Eagle Ford. Now, the Eagle Ford in our view is the best unconventional play in North America if you're in the right part of the play. And we believe that we are right in the middle sweet spot for the Eagle Ford. And the sweet spot is where you're in a volatile oil gas condensate window because that's where you have high compressibility, low viscosity so you've got high rates and high recovery factors and you've got significant fraction of that from oil and NGLs as you can see in the bottom right.

Now, we acquired this acreage at $300 an acre. We were one of the very first movers into this basin and we identify the sweet spot. And Al is going to talk more about how we identified the sweet spot and how the technologies that we're applying here are going to grow the value of this unconventional position and our other unconventional positions.

So in the Eagle Ford, we're going to add about 130,000 barrels a day by 2017, and that's an average of 16% compound annual growth rate over this period. And we've got more than 2,000 identified well locations still to drill. Of the 1.8 billion barrels of resources that you see here, we've booked about 200 million barrels in that so far, huge amount of growth, huge amount of potential remaining in the Eagle Ford.

So now what I want to do is to put the Eagle Ford, the Permian Conventional and the Bakken in the context of our overall Lower 48 development programs. So what I'm doing in this one is I'm adding to that other legacy development opportunities in places like the San Juan, the Barnett, the Gulf of Mexico, and the development opportunities that exist in our Niobrara and Permian unconventionals, and I'm going to talk more about both of those a little bit later in the exploration section.

But what we are adding here is 365,000 barrels a day by 2017, for about 5% to 6% compound annual growth rates. And let's talk for a moment about the graph in the bottom right here. Our current production in the Lower 48 is 60% gas and 25% oil. The incremental production that we're adding is 60% oil and 25% gas, complete change in the mix and the portfolio and it doesn't take a rocket surgeon to work out that this is going to improve the margins in our Lower 48 business.

So I've just gone through the details of our worldwide development program inventory and I hope I've given you some clarity and confidence and how we're going to develop the 600,000 barrels and why they're all coming with improved margins over our current base. So what I'm going to do now is I'm going to move on and I'm going to talk about our major projects around the world.

Now, all of these major projects are outside the Lower 48 and it really highlights the strength of our diversity and our legacy positions and our new positions. And these are going to add 400,000 barrels a day by 2017 and we don't have to wait till 2017. That production is going to start showing up in the fourth quarter of this year and 2014 is going to have added 150,000 barrels a day to our production and then growing to this 400,000 barrels a day by 2017.

So what I'm going to do here now is move around the globe starting in Canada with our oil sands position. Now, I assume that you guys all know who James Carville, the political commentator that worked on Bill Clinton's campaign. And he famously said one time during the campaign, he said is the geologist stupid. He didn't say geology, he actually said is the technology is stupid, I think.

Anyway, it doesn't matter we've got both of those covered, both the geology and the technology covered here because we have a top tier position driven by the geology assets based in the oil sands.

So we've got over 1 million net acres here. You can see in the top right, our steam oil ratio is top quartile average steam oil ratio. We are in the right path of the oil sands and we have a lot of additional that provides further optionality as technology develops to reduce the cost of supply. And Al is going to talk about that a bit later.

We have 16 billion barrels of resources on the oil sands just now. We're already the second largest SAGD producer. We've produced over 100,000 barrels a day in the fourth quarter of last year and we've got seven major project phases in execution just now. So I'm going to talk briefly about those major projects.

So, we have in Surmont our operated position, we have a very large scale phase 2 development going on. It's going to add about 120,000 barrels a day of capacity to Surmont. That's three or four times the size of a typical phase of development in the oil sands. First team from Surmont 2 will come in 2015.

We also have several projects going on in our FCCL joint venture at Foster Creek, Christina Lake and Narrows Lake. And Al is going to talk about technology development in the oil sands in a bit more detail. But what we see here about these projects and execution -- and this assumes that we do dilute our position somewhat in the oil sands.

But even with that dilution, we double our production by 2017 from 100,000 barrels a day to 200,000 barrels a day. And it comes at attractive margins about $40 barrel margins. So moving on from the oil sands now, across the Atlantic to the UK, and I'm going to deliver this next slide in the accent of the indigenous peoples of Scotland.

So here we have some really good investment opportunities and major projects here. The Jasmine project in particular is a really world-class project. We're going to see first production from Jasmine in the fourth quarter of this year.

And with a lot of additional projects, and we'll get through the details of the additional projects that are going on in the UK, right there in Britannia, Clair Ridge, East Irish Sea. But these projects are about 55,000 barrels a day by 2015, 2016 and then maintain that production essentially through the reminder of the five-year period.

Now, Jasmine is the largest discovery in the North Sea, the UK sector of the North Sea for many, many years. And there's a lot of remaining exploration potential and fault blocks around Jasmine. So in the well head platform that we're putting now in Jasmine has many spare slots and we intend to do the exploration from this platform so that we can immediately tie it back into their own production. So there's a lot of remaining potential in Jasmine in particular.

So this 55,000 barrels a day comes at cash margins of our own $35 of barrel. So again, above our existing average cash margin. To move across the other side of the North Sea to Norway, here we have several major projects underway. And Norway really is one of the assets -- it's the legacy asset that defines our company.

We have an outstanding reputation in Norway. In fact, we were just recently awarded a gold crown award as the best operator in the country and we're very proud of that. The fantastic group of people, fantastic asset based. And we have two major projects in execution around the Greater Ekofisk area. Remember I said that the Permian was the basin that keeps on giving? Well, the Greater Ekofisk area is a field that keeps on giving as well because we've been there for 40 years and we're going to be there for 40 more years.

And these two projects, Ekofisk South and -- Ekofisk rather and Eldfisk II, are going to continue to improve recovery. Ekofisk South is going to come on production at the end of this year. Eldfisk II at the end of next year, and there is several other major projects underway in Norway also. And these major projects add about 60,000 barrels a day by 2017 with our production base starting to show up at the end of this year. And again, that production comes at higher margins than our current base.

Let's move on now to Malaysia. Now, this is an area where five years ago we started from scratch in Malaysia and we've built a very attractive business there over these last five, six years or so. We've got four developments in execution, three deep water developments in Gumusut, Siakap, North Petai and Malikai and one shelf development at KBB.

Gumusut and SNP are going to deliver first oil at the end of 2013. And that will grow through 2014. Those projects add about 60,000, 70,000 barrels a day by 2017. Most of that showing up by 2015 and a very high margin as you can see in the chart on the bottom right. But we're not done with Malaysia yet. We've got four other discoveries that are either in the early stages of engineering or on the appraisal phase. So we're going to see additional growth from Malaysia in the years to come.

So I'm going to move on now and talk about our Australia Pacific LNG project. As you know, this is a large scale project developing coal seam gas to LNG. The LNG has been contracted the JCC linked price. We're focused now a two 4.5 MTPA trains. We have the plot space as you can see on the top left for two more trains, we have the EIA tell us to develop two more trains. So we have flexibility on this site to grow.

APLNG adds about 80,000 barrels a day of production by 2017, as you can see on the bottom left, and adds high margins. And this assumes that we dilute -- this production assumes that we dilute our position in APLNG a bit further.

So the project is about 30% complete, both the upstream and downstream part of the project. We recently went through a bottoms up review of the cost and schedule associated with APLNG. That bottom's up review told us that from a schedule perspective, we're still on track for our first cargo in the middle of 2015 from the first train. And we've actually accelerated our schedule expectations for the second train, and we now expect that to be operational by the end of 2015.

And we have seen some cost increases, about a 7% increase on an Aussie dollar basis. Most of the money in this project is spent in Aussie dollars. Those increases have come from drilling and gathering cost from some changes in the regulations associated with water handling, some increases in third-party projects that we participate in on the upstream part of this project and some increase in contingency for the remaining 70% spend. The downstream project, the work on Curtis Island, we see no increases there at all.

Now, since we sanction the project, the Aussie dollar has strengthened quite significantly against the US dollar. So, that 7% increase on sort of as spent dollar basis, which really describes the underlying characteristics of the project, that's going to look more like 20% to 25% increase on a US dollar basis, depending on how FX works over the next few years. So, that's the APLNG project.

Now we have several other projects that have just grouped together here that are going on, mostly around our legacy positions. So includes things like the Alpine West project in Alaska that's extending our infrastructure west and opens up more opportunities in the NPA, and projects in China and Indonesia. And I included this for completeness, but also because they add 60,000 barrels a day of production and high margin production over these next five years.

So to summarize what I've just gone through now was the growth and production and margins that's coming from our major growth projects, 400,000 barrels a day, all of it outside the Lower 48. So hope that's given you some clarity and some confidence where this growth is coming from and the fact that this growth is real and these projects are in execution.

So what I'm going to do now is change gears and start -- and talk about our exploration program. Our exploration strategy is to have a value-based balance of conventional and unconventional exploration in our portfolio. And we believe that we have developed a very balanced and valuable exploration portfolio. And this has been done -- essentially Larry Archibald has rebuilt our exploration portfolio over the last five years to deliver this, what we believe is an outstanding asset-based.

Now, in 2013, we're going to spend about -- we're going to spend about $2.3 billion in exploration in total. That's about 50/50 conventional, unconventional. There's about two-thirds in the US and one-third internationally. And it's a pretty heavy year in the US because we have some significant appraisal work ongoing and our unconventional positions in the Lower 48. And we're really ramping up our Gulf of Mexico deep water exploration program. I'm going to talk about both of those in a moment.

So I'm not going to talk about everything that's in our exploration portfolio for the sake of time. I'm going to focus on a few of the exploration assets in the portfolio. I'm going to start with unconventional assets in the Lower 48.

So I spoke about the Permian conventional position earlier. But our Permian unconventional positions is great too. We have a million acres held by production here. And we are high grading our portfolio to make sure that we're focusing first on the things that we really need to understand and can see the highest short-term value for. There are lots of long-term potential here beyond that.

So we're focused particularly in our exploration efforts and the areas outlined here in the Midland Basin and the Delaware basin. Some of those acreages we added recently to core up our positions there, so we're working through the exploration period and we're going through the production period.

We're seeing encouraging results and we expect to see significant growth from unconventional development in the Permian over the coming years.

I'm going to move now to what we think is potentially a new core area in unconventionals in the Lower 48 for us. And that's in the Niobrara. Over the last year or so, we've quietly built up 130,000 acres of a very consolidated position. And what we believe is a new sweet spot in the Niobrara.

We've drilled four horizontal wells in 2012. The rock properties look good. The early production results are encouraging. We're getting very high liquid yield. Season high liquid yields that are higher than Eagle Ford, not quite as high as the Bakken but somewhere between those two. So we feel very good about the high liquid yield. In fact, we feel so good about this that we're going to fill 32 wells as we move through the appraisal and then towards the development phase in the Niobrara in 2013.

So, moving out of Lower 48, now we're moving North to Canada. We have a really strong unconventional position in Canada as well. We're really focused around four plays where we have 600,000 acres in total across these four plays. We have over 100,000 acres in the liquids-rich part of Duvernay. We have over 100,000 acres in the liquids-rich part of the Montney. We have about 120,000 acres in the Horn River Muskwa.

Now, I think everybody knows that the Muskwa is one of the best unconventional reservoirs in North America. It's a beautiful shale. The issue in the Horn River area is that it's in the gas window, so it's a dry gas. So what we've actually done here is we've said, well, where is that beautiful shale exist elsewhere in Canada? And we've identified a play in the central McKenzie Valley and the Canol Shale, which is essentially the same shale that's in the liquids-rich volatile oil gas condensate window like the Eagle Ford. And we have built the 216,000 acre position there.

We're drilling two exploration wells right now. Well, we're drilling one right now and we'll drill one after that. And those are vertical wells. Just to make sure that we've got the right shale and we've got the right maturity that we believe in, next year we'll come back and drill horizontal wells and test this. This is a very exciting plea. Okay.

Now, part of our strategy has been to take our own conventional expertise internationally, where we think it makes sense. So looking for low-entry cost or looking for a very, very high quality proven shale. So I'm going to talk very briefly about a few of those just now.

So this slide covers Poland and Australia. We have a really nice acreage position in Poland. We've drilled several wells there already. We're focused now on this peri-Baltic region that's about 500,000 acres where we have 70% working interest and we're now the operator.

We think that this play really could work. We've got one horizontal well drilling. We're learning things about how to optimize a completion. We've got more drilling planned in 2013 to test how the shale thickens as we move to the north. So we are hopeful that this will turn into an attractive unconventional development opportunity.

In the Canning Basin, a very low cost entry into 11 million acre position. There we've drilled one vertical well so far. We'll drill one or two more this year. We recently reduced their equity in this position through part of a farm-in deal, a three-part farm-in deal that we did with PetroChina.

And we've just recently announced two further additions to international unconventional portfolio. Two deals in the Sichuan Basin in China. We believe that this marine shale is probably the best candidate for unconventional development in China.

So we've picked up two really significant positions, one with Sinopec in Qijiang area which is on the eastern side of the basin, and one with PetroChina on the western side of the basin that does this. And we look forward to working with Sinopec and PetroChina on these studies over the next few years.

And then yesterday I think, a move in to Colombia, into the La Luna Shale which we see is as a real world-class thick oil prone shale that we think could be a great unconventional reservoir. So, that final agreement is being completed. So over 100,000 acre position that we have 70% equity. We'll drill our first well there this year.

That's our quick overview of our international and domestic unconventional position. What I'll do now is to move on and talk about the other side of our exploration strategy, our conventional position. I'm going to start in Asia-Pacific, with two areas there, what we're doing in Australia and a new position we've picked up in Indonesia.

So we discovered the Poseidon gas field in 2009. It's a very large acreage position. We started an appraisal program there. And that appraisal program was focused on determining what's the right development method for the Poseidon discovery. So it's an extensive that started last year and will run through to the end of this year and into 2014. We recently farmed out 20% of our equity here to PetroChina as part of the deal I mentioned earlier.

We've also recently acquired a 49% interest in a very interesting PSC in Central Kalimantan in Indonesia. This is a play that hasn't been explored since before the Second World War and we're intrigued by this play. We've picked up a low-cost option, we're going to drill three wells through the end of 2014, and we see potential for a lot of upside in this play and we're very excited about it.

So I'm going to move West now to Angola. Now, you can see on the bottom of this chart that this Angola play that we're chasing is essentially the same play that's made so many large discoveries on the Brazil side of the Atlantic. We believe when we picked up this acreage, our hypothesis was, that play will exist on the Eastern side of the Atlantic as well. So we picked up these Blocks 36 and 37. Since we picked them up, the Cameia discovery has been announced, which immediately offsets our blocks a little bit inward.

So the play has been de-risked on this side of the margin. We have 2.5 million acres with an operated position here. We have just acquired 3D seismic. The 3D seismic is very encouraging. So the combination of the play being de-risked and the 3D seismic that we've seen gives us real encouragement of the potential about this deep-water position in Angola. We've just contracted a new deep-water rig that will arrive at the beginning of 2014 and will drill a four-well program back to back to explore this position.

And I'm going to finish the discussion on our exploration with our Gulf Mexico exploration position. Now, in about 2008, the round of time that Larry arrived, we stepped back and had a complete review of what we are chasing in the Gulf of Mexico, and over that time have completely rebuilt our acreage position here, refocus the position, refocusing on new plays, because we believe that the Gulf of Mexico has a huge amount of yet-to-find resources. And we believe that if you end the light with the right play, it's going to have a very competitive cost of supply.

So we focused our acreage acquisition on getting the right plays and you can see we've doubled the position just over the last couple of years. But now, one of the five leaseholders in the Gulf of Mexico. We saw those in the Gulf of Mexico, and a lot of our leases are held with long tenure on them. And that might not mean a lot to you guys, but it means a lot to us because it gives you a lot of flexibility on how you get through and explore this large acreage position over time. So 2013 we're really ramping up the testing of this acreage position.

We're going to drill somewhere between five and eight wells this year. The five that we know we're going to drill are shown on the chart. Now I'll talk about them in a minute. There are three more that we expect to drill, but we are still working on some of the details of those.

So before the Macondo event, we had actually already made two significant discoveries in the Gulf of Mexico in the Paleogene, at Tiber and Shenandoah. We've just finished drilling a well at Shenandoah, an appraisal well in Shenandoah. I'm going to describe what we learned there in the next slide. We will drill an appraisal well in Tiber this year also. So we're going back to our preexisting discoveries. We're also drilling three Wildcats. The Coronado well was actually spudded in 2012, it got to TD about a month ago. I'm going to talk a little bit about what we've learned at Coronado.

The Ardennes well, we just spudded in the beginning of this month. So we're looking forward to seeing the results of Ardennes. And the Thorn well, which is a Pliocene/Miocene target, is our first reentry as a deep well operator into the Gulf of Mexico. And we'll drill that in the third quarter of this year.

So let me talk about what we've learned from the Shenandoah and Coronado. Now, I can't give you a lot of details here, but what I want to do is to put these two discoveries in the context about our local position here. Now, we felt the next position was going to be a really good zip code for the Paleogene. And we picked up quite a significant acreage position.

Shenandoah appraisal well was a follow-up to the 2009 discovery where we discovered more than 300 feet of net play. The appraisal well was drilled about a mile away from that and we've got very encouraging results from that appraisal well. The Coronado Wildcat was nearby. Again, that's a TD and we've had very encouraging results from Coronado, too, and we expect to be back on location at Coronado before the end of the year.

And look at the follow-up potential we have in this zip code. They are den welled, as I spoke about. That's in the same area and that's spudded and drilling already. And that position that we have to the Northwest, 100% ConocoPhillips acreage, new 3D seismic, a lot of prospectivity. So we are really encouraged about how our deep-water Gulf of Mexico portfolio is playing out and expect to see a lot more to come from this as time goes on.

Okay. So that's me essentially going through most of the exploration portfolio. There are other exciting things, but in the interest of time, I haven't discussed all of them. But our strategy of a value-based balance of conventional and unconventional exploration, we think, is one that takes advantage of our competitive knowledge and allows us to be focused on a diverse set of opportunities for long-term growth beyond 2017.

So I'm just going to wrap up now. On this graph on the left-hand side is the one I showed you earlier. I'm going to change this now and show you that instead of in categorized by the type of project, characterized by the production that's coming from those projects. And what you can see here is that our North American gas position remains relatively production over these five years. We're not investing in gas in North America, but we do have associated gas coming with our oil and liquids-rich place.

International gas grows a tiny bit. NGLs are pretty flat. LNG is growing, oil sands is growing, but most of the growth is coming from oil. A lot of that in North America, but not only in North America, across the globe. And Jeff is going to refer back to these sources of growth when he talks in his part of the discussion about the margin growth. But it's very clear that the best incremental production is coming at higher margins than our base production just now.

So what I've shown you is that we have a diverse resource-rich portfolio, a high quality legacy base, a significant development program across the whole world associated with that legacy base in building new legacy position. Major projects and execution are going to start adding production this year and grow production continuously over the next five years, and a really strong exploration portfolio. And we believe the best portfolio is very well-positioned to deliver this high-margin growth and it's also very well-positioned to result in reserves replacement.

If you go through the math on the development program slides that I showed you, you'll be able to do some subtraction and division and work out that. Those development programs alone replace 60% of our production with reserves, just the development programs. You then think about the fact that more phases of our oil sands will be sanctioned over these five years. If you think about the fact that we've got several many projects, actually, in the early stages of engineering and appraisal that will be sanctioned over these five years. And we have our exploration program, thus resulting in discoveries that will be sanctioned over these five years.

We are very confident in our ability to replace significantly more than 100% of our production with new reserves as we go through these five years.

Okay. I started the presentation by saying that my goal was to give you clarity and confidence in our ability to grow our production and our margins over the next five years, and I hope I've been able to do that. But what I can tell you is that everybody in the Company, all 16,900 of us that Ryan mentioned, it's very clear to us what we need to do, very, very clear.

We have a lot of confidence in our ability to execute it and we're completely committed to getting it done. So that concludes my presentation.

Now as I went through the presentation, I spoke several times about the technologies that we are using and to protect our base for our development programs, for our major projects and for our exploration. Al Hirshberg is going to come up now and talk about some more details about technology program of why it's so important to us. So thank you. Al?

Alan Hirshberg - ***ConocoPhillips - EVP - Technology and Projects***

Thanks, Matt. So Matt has just taken you through our investment inventory and showed you how we're going to use that investment inventory to grow our production volumes on margins over the next five years.

What I would like to do next is explain to you how we're going to use our technical capability combined with that investment inventory to drive increased competitive advantage and shareholder value through our technology capability.

I'm going to take you through, same as Matt did, the different phases of production as I show you these technology examples, the base, our development programs, our major projects and then exploration. I'm also going to refer back to the 43 billion barrels of resource base that Ryan mentioned earlier that's shown on the pie chart on the bottom right.

One thing to keep in mind is that we've only moved to prove reserves 20% of that 43 billion barrels that's shown in the pie. So we've got 35 billion barrels more in that resource base that we're going to be using technology to drive it over and to prove reserves on economic basis.

So now let's move into some of my technology examples. I think you're really going to like the first one I've got for you because it's an example of one of the best reservoir optimization stories in the history of our industry.

I'm talking about the Ekofisk Field. You see the chart on the bottom right shows you that when we first developed this field in the 1970s, we thought we would only be able to get about 15% of the original oil in place in the reservoir out. Now after decades of an integrated technology movement and developing new techniques over the time, we now believe we'll recover well over 50% of that original oil in place.

So as you think about the low recovery rates that we have in our own conventional reservoirs today, I think it's useful to keep this kind of perspective in mind of what technology could do for us over long periods of time. I show a list there on the bottom left to some of the technologies that we've used overtime to get this kind of result. And I'll just mention one of them in particular is the 4D seismic that Matt referenced earlier.

The 4D seismic that we're using at Ekofisk is not your everyday 4D seismic. What we have at Ekofisk is what we call life of field seismic. So we have a permanent installation on the sea floor with arm-bottom cabling and geophones that allow us to essentially sort of push the button as often as we want to get a new update of how the oil and gas and water are moving in the reservoir and do that at a low cost.

So through these kinds of technologies, over this period of time with this increase in recovery, we've added over 2.4 billion barrels of incremental recovery over what we thought when we first developed the field. That's a huge win for ConocoPhillips and for that matter, for the country of Norway.

So as we look around our base resources around the Company through the legacy assets that Matt was talking about earlier and we think about how we can apply these same technologies, we see today over 2 billion barrels of additional resource that we think we can move over to reserves using these same kind of technologies and do it with good economics.

Next I want to talk about two advanced drilling technologies that we've developed in the Company that are really helping us around the world both of them we've honed these techniques in Alaska. Alaska is a place where we're working very hard to develop and produce every last barrel that we can get at economically.

So the first technology that we've been working on honing in Alaska is coil tubing drilling. This is a technique that we used to try to get hard to reach pockets of oil that have been bypassed and aren't being produced by our existing development wells and do it without spending a lot of money.

So in the example that I show here is our Kuparuk Field on Alaska. So what we're doing is we're using 4D seismic to illuminate pockets of oil that are in separate fault blocks or for whatever reason are not producing into an existing well bore. So these pockets are near the well bore but they're not producing and we can see that from the 4D seismic.

We could develop. We could access these pockets using conventional drilling, but it's just not economic. We needed a lower cost way to get out this oil. And this is what got us working on coil tubing drilling.

So with this technique, we're using very small tools on the end of coil tubing, it allows us to twist and turn through the rock. We can turn with these tools over 60 degrees in just a 100 feet of movement with the drill bit. And so that allows us to go right to these pockets that we found with the 4D.

In this case we show what we call an octolateral. So we've actually found eight different zones near this well bore that we could go and hook up using coil tubing drilling. And so we've done that, all eight of these zones that were not producing tied back to this one well bore. So that's a very cost effective way to get at those zones that weren't producing before.

And so it makes economic sense for us even in a high cost place like Alaska.

Second drilling example I'd like to show you in Alaska is casing drilling where we're drilling with the casing in place and also the ability to steer, steerable drilling liners. And so what drives us to this technology is it enables us to be able to drill through unstable reservoirs, unstable well bores, pressure-depleted formations.

So normally when you have these well bore instabilities, if you try to drill and then come back and run casing, you can't do it fast enough because the well bore collapses. So here, we're actually using the casing to drill. And so the casings are already in place as we drill the hole. That gives us a mechanical method to be able to still access those resources.

So this technology contrasted with the last one, the coil tubing drilling that I showed you, with coil tubing drilling, we're accessing resources that we could get to conventionally, but we're doing it at a much lower costs. Here we're accessing resources that physically we just couldn't get to using conventional techniques from our existing well pads.

So it's opening up significant additional resources for us. And as we have perfected this technique in Alaska and now we look around the world in our diverse portfolio where else we can use this technology, we see hundreds of millions of barrels of additional resource that we're going to be able to access that we couldn't get to before using these techniques.

So that's two or three examples in our conventional reservoirs around the world. What I'd like to move on to next is the unconventional space. I think you could see very clearly from what Matt showed you that unconventional reservoir development is shaping up to be a very big deal in ConocoPhillips. It's a big part of our growth plans going forward.

So I want to take a little bit of time to take you through some of the technology that we've developed that's going to allow us to do this in an industry leading way.

So I think we've been able to develop in the Eagle Ford, as a great example for us to use, an industry-leading position in what everybody can see is an industry-leading shale position. And of course some people say that these unconventional reservoirs are really the province of the smaller independent. The low guys can now compete the bigger companies.

I heard last night that some people think that unconventional development is just a commodity thing. Anybody can do it. It's all the same. You just look over the lease line see what the other guys are doing. I'm going to show you some data on these next few charts that I think will demonstrate that that's not true in our case.

On the left is four key technical capabilities that we think you need to have to really be a top-tier unconventional reservoir developer. And in my subsequent slides, I'm going to delve into each of those four areas in more detail.

But first, I want to focus in on the value that we're creating using these technologies, using the Eagle Ford as an example. The plot shows you some data from a Wood Mack study where each dot represents one of the competitors in the Eagle Ford and they've calculated on an NPV10 basis what the value is that's been created per acre for each company's acreage position in the Eagle Ford.

And you could see that ConocoPhillips has a leading spot there with our red dot up near the top. The interesting thing though about this work that Wood Mack did is it's all done on a money-forward basis. It ignores what your entry cost was in the way that they've calculated this.

So when you look at the value that they show for us per acre, $35,000 of NVP10 per acre and then you consider that we acquire this acreage for $300 an acre, that's really impressive shareholder value creation.

It's a little less impressive, some of the other dots that maybe kind of high up on the chart, but the Company has paid dollars per acre similar to that NPV10 value to get into the play. That's a big distinction I would make between the two.

So how is ConocoPhillips able to develop this enviable position that we have in the Eagle Ford? I want to spend some time on the next few charts showing you some of the technical methods that we've used. And the first thing that comes to mind is sweet spot identification.

THOMSON REUTERS

I think it's clear to everybody that not all of these shale plays were created equal and within given shale play, not all the acreage was created equally. And so if you're going to be good, the very first step is you got to be able to find the sweet spots in a new area.

When you do that, you get the kind of results that you see in the bottom two plots. On the bottom left, ConocoPhillips our averaged well produces a lot more than our competitor's average wells and we can ramp production very quickly even without running too huge of a number of rigs, we've been able to ramp from essentially zero in 2010 to 100,000 barrels a day by the end of last year.

So how do we do this? We use a multi-disciplinary approach. We have a dozen different technical disciplines that we have tightly integrated together working to develop our proprietary methods for how we find these sweet spots.

And I think it's pretty clear as you look around the industry that there are very few companies that have been able on a repeatable basis to be able to identify these liquid rich sweet spots in a new play and to get in early at a low cost of entry in a mass of significant acreage position in the sweet spot of the field.

And I think Matt just showed you a couple of those that we've got coming, the three that everybody knows about already that we've had a low cost of entry and that are already successful are the Eagle Ford and the Bakken and the Permian, but Matt was showing you Niobrara and the Canol, the examples of additional places where we've used our technical capability to get in early at a low cost and find what we think are the new sweet spots. And as he mentioned in the state of Niobrara for example, we've already got drilling results that tell us that we have identified a new sweet spot there. And it will soon be on our list of additional places that you'll hear about when we've been able to accomplish that.

So some of the techniques that we use to generate some of these results is what I want to show you on this next page. To really be good at full field development, optimizing the full field in an unconventional space as you move from the early phases into full development we think requires a combination of disciplined science which informs analytical models combined with the ability to go to the field and rapidly experiment to feed that and take good data to feed back into your models.

So what we observed oftentimes in our larger competitors in the unconventional is they seem to spend too much time perfecting the science and their models don't move quickly enough to the field. On the other hand, what we see sometimes on our smaller competitors is that they don't have the capability to even do the science and really they're in trial-and-error mode. They're out in the field just trying things.

And when you're working that way, it doesn't leave you with a predictive capability that you can use to go to that next play and find the right spots and be able to move quickly to optimize your development.

So I think some of the proof points of our ability to do this are shown there on the chart. In the Eagle Ford since 2010 on the same acreage using these technologies, we've more than doubled what our estimated ultimate recovery is, more than a 50% growth in the Bakken.

A little example here on the bottom right shows you the kind of things we do to achieve that result. The light blue part of the plot shows you for a series of wells in the Eagle Ford what our average production was using a certain completion technique that we were using last year.

Then we had a new idea of a single change to the way we were doing the frac jobs, we test it on our models, we move quickly to the field to try it out and saw it was good and switched to that, implemented that change. And then if you look at the next batch of wells that we drilled and completed using this new completion technique, that's what's shown in the dark blue wedge there.

So it's interesting that just one good new idea implemented quickly can give you a very significant uplift in your production and your recovery in a given area. So the bottom left is one last thing I want to mention on this chart.

When we go to the field, we're not as I said earlier just in trial-and-error mode. We're taking a lot of high quality data. What's in the picture there is a fiber optic base system that we've developed that straps to the outside of the production casing and allows us to measure in real time pressure and temperature.

So while we're submitting that casing in place, while we're pumping the frac job during the flow back and during production subsequently, we can see the temperatures and pressures. What this has done for us it allowed us to really perfect the way that we do these frac jobs, the way we execute them and we can see contrary to what you read about sometimes, we could see that in our completions, everyone of our fracs in this multi-staged frac is producing into the well bore. We're getting production from each of our fracs and we could see that in real time using these techniques.

A couple more capabilities you need to have to be one of the top operators in the unconventional is you need to be a very efficient driller and you need to be good obviously at production operations, so a little bit of data on those two things on this chart.

In the top, you see the bar chart that's again third-party data just like all the data I've been showing you on these pages that shows how many rig days has each of the competitors in the Eagle Ford needed to drill 10,000 feet a hole in the Eagle Ford. And you can see in the red bar for ConocoPhillips that we're amongst the most efficient of the drillers in the Eagle Ford.

And I should point out that this is data from the period before we've reached the held-by-production status. We expect to get to HBP status by this summer. And then at that point, we'll move to pad drilling and that's going to improve our drilling efficiency significantly even further. So this is even before that point in time.

Another point I'd like to make is that's an advantage for a company of our size and scope is that we were able to have a lot of expertise in the supply chain side of things. And so in early last year when we saw gas prices dropping in the US and there were some softening in the contractor market, our supply chain experts were able to move very quickly and renegotiate our stem contracts. And we saved over $200 million last year from those renegotiated stem contracts.

I also want to mention a little bit about production operations. We have put in place in the Eagle Ford what we call the IOF, Integrated Oil Field of the future. And so what we've done here is we've installed our own private WiFi towers across all of our acreage in the Eagle Ford. This allows our personnel in the field to use iPads and other mobility devices to be able to access real-time operating data across the entire field and to be able to collaborate with each other and their engineering colleagues back in the office.

In this particular picture, you see a couple of our guys at a construction site and they're able to use their iPad to access construction drawings back in the office, so a lot of capability that that gives us. And we think the combination of all these things allows us to get the most out of our own unconventional resource developments without over capitalizing.

So that's a fair amount of detail around some of the techniques that we're using, the technologies we've developed for unconventional. What I'd like to do next is move to another important area for the Company and that is the oil sands.

You saw on my very first slide when I showed you the resource pie that the oil sands is a very large part of our resource in the Company and so it's an area that we've been working on a long list of ideas to improve the economics of our major developments in oil sands for a number of years.

And these ideas start out, come from our people that we test them with our models and in the laboratory. We move to the field to verify that they're going to work once our models tell us we have a good idea. You see a list there of some of the ideas that we're now implementing.

But overall the target here for us as we move forward into our new major project developments in the oil sands is to reduce our cost of supply by $20 per barrel. That's what we're after. And you can see from the little bar chart in the bottom right that we're well on our way to doing that.

The first green bar shows you the ideas contributing to that $20 reduction that we're already implementing in the field. They've been fully tested. The next green bar shows you, it represents the ideas that look good but we're still doing some development and testing on and together we think we'll be able to get a $20 per barrel of reduction on our cost of supply.

When you look at the ideas that we're chasing to do this, fundamentally they're all aimed at reducing our steam oil ratio our already first quartile steam oil ratio that Matt showed you earlier. So when you do that it brings improved economics, it reduces your cost of supply, but it also reduces your water usage and it reduces your air emissions.

And so it's a win-win all around as we develop these technologies in the oil sands. And with our 16 billion barrels in our resource base of oil sands, we have a big multiplier for any improvements that we come up with in oil sands technology.

The final example that I'd like to show you is some work that we're doing in technology to improve our exploration performance and I want to focus in here on the deepwater. Frankly in deepwater technology, it's an area where we've had some catching up to do. And that's exactly what we've been doing over the last handful of years in deepwater technology.

We have very significantly expanded our proprietary in-house seismic imaging capabilities and we've tightly integrated that with our expert basin modeling skills. You can see that in the little picture there on the right shows you those two technologies being integrated.

Those two technologies combined with our ability as an independent to move quickly have given us a competitive advantage as we've moved into the deepwater. And so I think you've seen a very advantageous prospect portfolio that Matt showed you earlier that we've been able to develop in both the deepwater Gulf of Mexico and deepwater Angola using these technologies.

And as Matt also mentioned our early results from our exploration wells are proving up the competitiveness of our prospect portfolio. In addition we've got two operated new build drilling rigs coming next year that's going to open our aperture further and allow us to increase our potential here in the deepwater.

So if I can wrap up now to summarize I think we've really built an impressive team that's working on our technology in ConocoPhillips. We've got the people that have allowed us to create competitive advantage and differential value creation for our shareholders using technology.

We're not trying to be the leader in all across the waterfront technology. We're targeted to the areas that directly benefit the things that are in our resource base and allow us to grow our production and our margins cost effectively, developing a capability that's allowed us to compete around the world for new acreage.

And so I think what we've showed you so far this morning Matt has taken you on a tour around the world of all of our investment inventory and how we're moving it to grow our production, our margins, improve our returns. I've showed you some of the technical methods that we're going to use to improve those results even further.

And now I'd like to call up Jeff Sheets, our Chief Financial Officer. And he is going to tie all this together here and show you the impressive financial results that come from all of this work.

Jeffrey Sheets *- ConocoPhillips - EVP - Finance, CFO*

Thanks, Al and good morning everyone. So we had Ryan start the morning with a bit of a discussion about strategy. So the strategy in short form is we're investing for profitable growth and we're pairing that profitable growth with a compelling dividend and we think that that's the recipe for creating strong and predictable returns for our shareholders.

So then we had Matt walk you through a lot of granularity about where that growth is coming from and the margins that come with that growth. And what Al just talked about and the point we want to make sure that is understood is this is a technology-driven business. And being a company this size and scale and with the technical capabilities of ConocoPhillips has created shareholder value in the past and it's going to create shareholder value for us going forward.

So what I would want to do is wrap it up and talk about numbers and particularly cash flow numbers. And if there's kind of one fact that I want you to take away from this morning's presentation is that the investments that we're making are going to create an incremental $6 billion to $7 billion of cash flow.

So when you put that number in perspective, if you look at our assets and when our portfolio that are going to be part of our continuing operations going forward, in 2012 those assets generated less than $15 billion in cash flow.

So if you have the same kind of price environment we had in 2012, you'd add about $7 billion at cash flow by 2017, so it will be $15 billion going to $21 billion, $22 billion at cash flow. If we have that price environment like Ryan talked about earlier where you're more than $90 real WTI then you're maybe closer to $6 billion at cash flow.

But again, the key message is we've got a step change in cash flow coming. So what I want to just talk to you first about is what's the financial strategy for making that happen? It's a pretty straightforward strategy. I mean what are we doing? We're taking cash flow from operations and we're taking proceeds from the sales of non-strategic assets and we're reinvesting that in a set of programs and projects which are going to take our production from 1.5 million BOE today to 1.8 in 2016 and 1.9 in 2017.

And that production is coming at good margins so that's our cash flow is growing to the point where we can fund the capital program and fund the dividend that's higher than today's dividend and fund the capital program that continues to create growth for the Company.

Now we've talked a lot about growth this morning, but it's not going to be growth for the sake of growth. We're always going to continue to be focused on returns as well. And some metrics like ROCE are going to continue to matter for us and I'll talk a little bit about our thoughts around that in the subsequent slide.

We also recognized that we operate in an environment where there's a lot of volatility in commodity prices. So having a strong balance sheet is key for us going forward and it's going to be one of our priorities. But the top priority for us as Ryan mentioned earlier is the dividend.

We are a company that believes that we're an industry and we're of a sized company. And a significant part of what shareholders are looking for from us is a dividend that they can count on as a stable part of their shareholder return and they can count on that growing overtime.

So in the near term though executing this financial strategy is helped by the execution of an asset sales program and that's what I want to talk about next. So at the end of last year, we announced about $9.5 billion worth of asset sales. And you see the list of assets up here, the exit from the Kashagan project in Kazakhstan, selling our assets in Algeria, Nigeria and the Cedar Creek Anticline assets in the Lower 48.

Now what all these assets have in common is they are non-strategic assets for us. They don't help us meet our long-term strategic objectives. And we're doing all these asset sales in a manner that's very tax efficient.

And we've sold these assets to buyers who view these as strategic assets and that's reflected in the value that we've received for the assets. So we've received full value for the assets. And now you look at these assets as a whole. In 2012, they generated a little over 60,000 barrels a day at production and they represent a little bit more than 350 million BOE of reserves. So what we're doing is we're taking the proceeds from the sale of these non-strategic assets and we're reinvesting them into things that are core to our portfolio going forward.

And it's those strategic assets that we're investing in that are going to create the cash flow growth we've been talking about. So let me talk about those. So this is the same slide that Ryan had up earlier and really this is the same slide that we've been using basically for the last year. It shows that a lot of our growth is driven by these five key growth areas that have come in at higher margins.

And as Matt went through with you this morning, there's a lot more in the portfolio than just this. There's a lots of other investments that are happening in the base part of our portfolio which have a significant impact on mitigating our base decline.

So what I wanted to do with you next is to put all this together and say well what's changing about the portfolio? So I'm going to spend quite a bit of on this slide. And I was going to say to go ahead and get comfortable in your chair but I've been sitting in that chair and I know that's just not really possible.

So as we were preparing this presentation, we kind of voted this slide is the most likely to show up in analyst write ups after the meeting, so I have to see if we were right about that. Because this slide is really at the core of what we're trying to do as a company and to create incremental cash flow growth.

So in 2012, we produced about 1.5 million BOE a day from the assets that are going to continue on in our portfolio. So if you fast forward to 2017 and you ask yourself what's different about our portfolio compared to 2012, that's what where we want to get across here.

So production would have grown to around 1.9 million a day, about 400,000 barrels a day of increase, but what's important is a couple of things about that 400,000 barrels a day. The first is what kind of products make up that growth and the second is where is it coming from because it's coming from areas where tax rates are generally lower than the average of our portfolio today.

And just to make sure that we're clear about what I'm doing here is I'm comparing 2017 to 2012, so that includes the impact of the declines in our base production, it includes the production from our development program and it includes the production from our major project. So this is an all in comparison of what's going to be different.

So of the growth that we're talking about, about half of it is going to come from oil production. Of that oil production, about 70% of that oil production comes from the Lower 48 and the rest of it is coming from Malaysia and projects in Europe.

And so where it's not coming from is places we've had relatively higher tax rates like Alaska. If you think about that kind of makes sense because we're drawing to make investments in areas where there's lower tax.

So you step back and look at this and our oil production overall is coming from areas with the lower average tax rate than our current portfolio. So next up, we've got about a quarter of this, about 100,000 barrels a day is going to come from the Canadian oil sands. Again, this is an oil linked product, obviously, in an area with a relatively favorable tax regime. And this is a layer production that has long life, low decline, high margin.

If you think about the oil production growth, about 15% of it is going to come from LNG, again another long life, low decline, high margin piece of the business this coming from the APLNG project. And then of this growth, only about 5% of the growth comes from NGLs and those NGLs are production increases mostly from North America, and about 5% of it comes from international gas production.

As important as what's on this chart and probably what's not on this chart and that's natural gas production from North America. So as Matt talked to you earlier, we see that our North America natural gas production is basically going to be flat, as production from associated gas with the shale developments basically offsets decline from our base production.

So you look at this all in and you were adding 400,000 barrels a day of net growth, if you look at the average cash margin on this net growth, its $40 to $45 a barrel. And you can see if you mix in that with our portfolio today, which is averaging around $25, maybe $27 a barrel of cash margins that what's going to be driving both production higher and margins higher.

And to count one last point before I leave this slide is that this isn't all happening in 2017. It really starts to happen at the end of this year as major growth projects start to come online. So you'll see meaningful increments up on production and cash flow in 2014 and more in 2015 and on up to this $6 billion to $7 billion a year that I've talked about by 2017.

But it's not just growth for the sake of growth. We're going to be disciplined about how we invest. We're going to continue to look at metrics like return on capital employed is an important metric for us. We put up this chart here where we compare our return on capital employed to those of the largest independent E&Ps. And normally, when we show comparative charts like this, we'll show us against what we consider our peer group which actually includes the integrated majors as well. But we wanted to show an E&P only comparison, that's really hard to parse that out of the integrated results. And their results get pretty heavily affected by what's going on our refining and chemicals.

So, as you can see we do relatively well on this metric, but we're really not happy with where we are. So, we want to see our returns on capital employed improve both on a relative basis and an absolute basis over time. So how do we do that? One way, you're always going to be focused on ongoing cost and ongoing operating efficiency as a way to improve our returns on capital employed.

Probably I have to stop here, and just to mention that in the back of your books, we've got some specific guidance on 2013 on cost level. So, it would give some guidance for 2013 on controllable cost levels, DD&A. What do we think the corporate segment net income is going to be, as well as a little bit more guidance on how we would see production moving on a quarterly basis during 2013.

But, you know, so back to talking about returns. So what's going to change our returns on capital employed, well asset sales make a difference. Particularly, when you think about things like the Kashagan project where we've got $5 billion of capital employed on our books today that's not generating income. So you take that off and that helps ROCE metrics.

But, at the same time, we're investing pretty heavily in projects like APLNG and oil sands which are put in capital employed on our books now but not creating a lot of income. So near term, probably a relatively flat portfolio for ROCE, but then ROCE grows as these major growth projects come online in a few year's time.

Now we talked a lot about growth in returns but one of the keys in our business is maintaining a strong balance sheet. I wanted to say a couple words about that. So we ended up last year with about little over $4 billion -- $4.4 billion of total cash on our balance sheet. We got asset sales we're executing this year that will bring in about $9.6 billion. So you can see our cash balance probably grow as we go through the year.

We ended the year with $22 billion of debt. Short term, maybe that debt comes down some as we generate all this cash. We don't feel like longer term that we need to bring our debt balance down from the $22 billion to the level that we are at today.

We've got A1 credit rating that reflects a substantial amount of financial flexibility. And if you think about the growing cash flow profile for the Company, that implies more financial flexibility, more depth capacity for the Company going forward. So if you think about funding the growth program that we have, it's not unreasonable to think that we're going to fund part of it with our cash balance and that we could fund part of it with debt as well.

So if you look, this is kind of how we compare on debt-to-cap compared to our peer group. We got about 30% debt-to-cap today, A1/A credit rating. We think about where we want to be longer term. We think we're about on the right spot from a capital structure perspective. We don't see any need to significantly de-lever. We don't see any real advantage to trying to go to what we would see as a more excessively conservative capital structure.

So what that means is that in terms of something like a debt-to-cap ratio is it will probably be in a 25% to 30% debt-to-cap ratio going forward. So I wanted to wrap up my financial discussion with some thoughts on the dividend, because as Ryan said earlier that is our highest priority use of cash flow.

So if you look at where we are among our peer group now, we're paying a dividend that's around 4.5%. That's right up there with what the European majors are paying right now. It's a fair bit higher than what the US integrated majors are paying. It's really quite differential to what's being paid by the independent E&Ps.

Again this is a key point that you will almost hear us emphasizing. This is a core part of our strategy. We believe that we should be getting a significant portion of our cash flow back to our shareholders in the form of a dividend. I think that enhances the capital discipline and it's part of the mix of creating strong returns for our shareholders.

So as we think about dividends going forward, if you look back, we've increased the dividend really rapidly at ConocoPhillips over the last or early since the merger of ConocoPhillips back in 2002. We're creating a lot of incremental cash flow going forward and that's going to give us scope to continue to increase the dividend going forward.

So just to wrap up the financial discussion, so just in a nutshell what are we doing here? We're taking cash from operations, proceeds from asset sales, investing it in a series of programs and projects which are taking our production levels from 1.5 today to 1.8 in 2016, 1.9 in 2017. So think about that, that's a 25% increase on our production.

But because of this production it's coming from higher margins, it's more like a 40% to 45% increase in the cash from operations that we're going to be generating. That brings us to the point where we're going to be able to continue to grow as a company and pay a dividend that's higher than what we're doing today.

So that concludes what I wanted to say on the financial side. Ryan's got a few things he wants to say to you to wrap the meeting up, and then we're going to turn it over to some questions. So, I'll turn it back to Ryan.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Thank you, Jeff. So let me recap a little bit about what you've heard today and then open it up for some questions.

So hopefully, you've seen we've opened the hood on this growth engine. You got a peak under the hood see what it's all about. Its high returns, its high growth, its high margin. Matt showed you where it's coming from, our base legacy assets, our development, our projects.

Al showed how we're using technology and innovation to improve the underlying value of all those assets we have in the portfolio, and the compelling and momentum building exploration program that we're building. And Jeff finished it up. The growth is real, it's in execution. We're directing those investments to higher margin opportunities that grow our cash flows and it fund our capital and our dividend plans over this time frame that you've heard about today.

So I'm going to end where we started it all. This is what we're about. It is run the business well. We know how to do that. We're focused on the execution, running our base business well. Dividend remains the highest priority. We're financially strong. We know what we're doing. We know how to fund our programs. We have it in play. We're going to grow this thing 3% to 5% over the next five years. We're going to grow the margins 3% to 5%. And we have a laser like focus on improving our returns. And that's the new class of investment that ConocoPhillips offers to our investors.

So let me end it there and I'd be happy to take questions. The team is here, I look forward to hearing questions and comments that you might have about the plan. [Doug] over here.

QUESTION AND ANSWER

Doug Terreson - ***ISI Group - Analyst***

Ryan, ConocoPhillips' record of execution has been pretty positive overtime. But when you consider that you're portfolio today of investment is probably as strong as it's been in a decade or certainly for some time, you've got a lot to work with. My question is, how does a company mange for execution risk, meaning how do you prevent delays and cost overruns, such that you're able to attain this 50% rise in cash flow that you talked about today?

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Yes, I think Matt an Al talked a little bit about it. It is a big belief, you got to be very integrated and functional excellence is important in this business. So it is about operating excellence. We have a four legged stool approach operation's excellence plan. It's about asset and operating integrity. It's about production and surveillance and optimization. It's about planning and reliability. So, it is about running the base business pretty well. It's our legacy. It's what we've done really well.

I talked about things we're trying to change in this company, the culture we're trying to change, and I talked to our people and I tell them, here's what we're not going to change. It is about how we execute. It is of our passion for safety in the environment. That's absolutely what we're not going to change.

And we've been building a lot of functional excellence on the major project side too. We're going to have our instances where things get, you know, we struggle a little bit, but we've come a long ways in terms of capability and capacity on the major project side. We actually have a history of doing that well and we'll continue to do that well. But we understand we're got to protect the base. Our license to grow our license operate is fundamental to that part of the business.

Next to you, Doug Leggate, please.

Vladimir dela Cruz - ***ConocoPhillips - Director, Investor Relations***

Could you please state your name and your firm you represent please.

Doug Leggate - ***Bank of America/Merrill Lynch - Analyst***

Hopefully, you know that. Doug Leggate from Bank of America. Thanks Ryan. I'm going to try two, but they're interrelated so hopefully I'm not being greedy with time. Obviously, there's been a lot of focus on the dividend and there are a lot of comparative charts and cash flow growth and projections and so on, but there's a couple of things that underpin that, one is that WTI is not $10 below Brent. And secondly, the companies you're comparing yourself with are paying their dividend out of cash flow whereas you're not.

So my question is, why, when you're spending $2.5 billion in exploration which is two-thirds of your dividend, and you're projecting this growth in cash flow which is getting a lot of subjective assumptions. Why is dividend still the core priority?

And the related question is, the exploration program is still somewhat embryonic, why the rush? Why not get to that cash flow coverage position before you start spending so aggressively in exploration? Thanks.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Well I think it's a bit of what I call a paradox symmetrics in this business. It's not just about delivering the next five years, but this is six, seven, eight-year cycle timed business. So you better be working on things today. In fact, most of my time, my leadership time has spent on what can we capture in the portfolio today that's going to be growth beyond 2017. The rest of steps are in execution.

So it is important to balance your spend. It's important to spend money in exploration. It's important to think about what the next decade has in store for this company based on the cycle times we experienced in the business. And as Jeff said, it's a mature business. This is a business where capital discipline is important. You better be carefully how you spend that last billion of dollars because it does matter where the returns come from. And the dividend puts capital discipline into the Company. So, we think it's an important part of our offering.

It underpins our performance and the returns that we offer here. And we're pretty committed to that dividend. So, I think when we look at the program, we look at the investments that we've got over the next five years. We look where our cash flows are going, we can afford the dividend that we're paying. The cash flows are coming. We're going to be able to afford the dividend and the capital program long term. And we can still invest in exploration to make sure that we're growing and we're adding opportunities into our portfolio that'll represent production reserves, growth and margin beyond 2017. And that's important.

So, Paul? You'll all get a chance, don't worry.

Paul Sankey - ***Deutsche Bank - Analyst***

Hi, Paul Sankey at Deutsche Bank. Ryan, you highlighted quite deliberately that you saw the potential for more disposals further down the road beyond the existing program, and you mentioned too, growth assets actually. I was wondering why you wouldn't want to rationalize the base and the decline challenge that you described here and settle down perhaps at the more mature areas as an alternative plan, thanks.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Well we continue to look at the portfolio. So when I say the coring up for the portfolio is largely done with the assets that we did. We're always looking at the portfolio and some of the more mature declining less strategic assets. You've seen as we've done a bit of that in the UK sector of the North Sea, we've done some of that in the Lower 48 and we've done some of that in Canada. We'll continue to burn the assets. That's just a logical thing to do to keep the portfolio healthy and manage the base.

What I talked about is moving from a strategic sense, talking about the larger coring up that we've done around Kashagan, Algeria, Nigeria and some of those assets is we are trying to rebalance the portfolio. So we are looking at cost of supply, and wanting more flexibility in the portfolio and that's why I talk about lighting up in some of these longer life assets and freeing up some additional capacity that we can invest in to a growing unconventional position and some deepwater success that we see coming.

So want to be prepared to fund that because we think that deepwater has got a competitive cost of supply and fits well within our portfolio. But you'll see us continue to do a little bit of cleanup, probably not at the level that we've described here today, and announced today, or announced in the last year or so.

Paul Sankey - ***Deutsche Bank - Analyst***

Thank you.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Back there.

Gary Low - ***Epoch - Analyst***

Hi, Gary Low from Epoch. Ryan, just two quick questions, one is one the Canadian oil sands with the differentials, the depressed, would you consider deferring the growth projects and potentially the sale? And two, on the midstream infrastructure, I think previously, you commented that if you were to spend $500 million to $1 billion in CapEx, you would consider an MLP as a more efficient funding mechanism. Is that still the case and timing? Thanks.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Well, we are seeing a bit of dislocation. I mentioned it in my opening a little bit between, and Doug you mentioned it as well, what WTI is not trading at $10 as well. Yes, today it's not trading at $10, maybe NGLs or bitumen is a bit of more necked back. Again, we're thinking about this business over five and 10 years. We're going to go through a bit of cycles where we see a bit of dislocation. We're seeing that today.

But we do believe infrastructure is coming. We do believe that pipelines and ways to evacuate the group. So we don't think longer term that those differentials are going to persist. In terms of MLPs we're always looking at different options and tools within our portfolio to improve the returns. And we'll continue to look at those all the time.

In the back there.

Faisel Khan - ***Citigroup - Analyst***

Thanks, Faisel Khan with Citigroup. Just on some of the similar topics, you're $6 billion to $7 billion operating cash flow growth number. Can you just elaborate a little bit more on what assumptions you make? I mean, does WTI trade $10 under Brent, $20 under Brent. Does WCS trade $50 as bitumen prices? Where does all that pan out and is there a recovery in the gas prices? Are you guys assume a recovery in the natural gas price in the US and how much does that make up of the cash flow growth from where we are today?

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Yes, so in that margin analysis, so I've tried to be clear right upfront what that represented. That was Brent in $100, WTI $90, so long term attentive and WCS at $70, $20 below WTI, and a $3.50 Henry Hub, so we don't really show much increases on the dry gas. We had to pick a price deck. We had to do something to try to describe the margin analysis to you and that's what we chose.

Over here, Ed?

Edward Westlake - *Credit Suisse - Analyst*

Thanks, Ed Westlake, Credit Suisse. I think Doug asked about execution risks. I'm still focusing in on the confidence interval on the production growth, there was a bit of a change I guess from prior guidance. I think in 2016, you were above [1.8] and in this guidance you're slightly below 1.8. Is that all disposals? That's the first question.

And then, coming into some of the conventional plays, you've got resource numbers, you've got production. Can you talk a little bit about what's included from say, the Horizontal Permian, from the Niobrara, from the Canol and maybe the Three Forks in the Bakken in terms of those projections that you've laid out today.

Ryan Lance - *ConocoPhillips - Chairman, CEO*

So I'll probably have Matt help me out a little bit on some of that. Well let me go to the last one first, which is what we've gotten our plans. What we came up before and we had maybe, slightly above [1.6]. So there are some incremental dispositions that are now built in our plans and one of those is Cedar Creek organic line. That was an opportunity that presented itself at the end of the year and it was non-strategic, does the investments that we saw going forward didn't compete in the portfolio, and it made sense to the person that we or the Company that we sold it to, and they paid us full value for it.

So it made a lot of sense on both sides. That's a little bit of the difference. Plus, we have factored in some of those rebalancing that I've talked about in terms of the oil sands and APLNG.

In terms of what is in the plan our in the future, we've taken a risk to view the Niobrara development and that shows up in our plans because we've been successful and we're thinking about that in terms of how quickly we can ramp that up and get that in. But that's the only I think that's in the plan. And Matt, you might want to address that some more.

Matthew Fox - *ConocoPhillips - EVP - Exploration & Production*

So in the top blue edge on one of those slides refer to production coming from other North American unconventionals. And as Ryan said, that's a risk weighted view and it's about 90,000 barrels a day, and that's a risk weighted view where we've just included some of those conventionals working. So its Niobrara risk view, Permian unconventional and the Duvemay, I think are the once that we chose to put in that category.

So it's about 90,000 barrels a day of the production by 2017 is coming from those other uncoventionals. There's a lot more potential in that in the portfolio that I hope I made clear, but that's what we put in to the base case.

Ryan Lance - *ConocoPhillips - Chairman, CEO*

Get [charging] here.

Unidentified Audience Member

Thanks, Ryan. Just had a question on the role of M&A in business development going forward, the legacy company of the last decade has done a lot of stuff. Some of which was good like the Cenovus Joint Venture, the low cost Eagle Ford acquisition. Some of which you've ended up reversing, selling down APLNG, getting at a shot et cetera.

Can you talk about the philosophy going forward? Is there a different approach and I guess in particular just some of the business development stuff in terms of how you evaluate projects, or is it just that you feel better about the organic growth than maybe you did over the last decade.

Ryan Lance - *ConocoPhillips - Chairman, CEO*

When I talk about what's changed in the Company, it is has been a movement of what's grown this company over the last 10 to 12 years through the M&A channel. And we have turned our focus in the last couple years, and as we've come out as an independent company on our organic growth. So you talk about the role of mergers and acquisitions. When we look at it, we just think the option value associated with being a good explorer and finding it organically has a lot better returns for the business, for our shareholders.

When you talk about acquisition I have to parse that just a little bit. I'm not talking about company acquisitions, but we're very active in land acquisition. That's a large part of our exploration spin. We acquired over 800,000 acres just in the last year and a half, and we're doing that to try to get a first mover position or a very, very fast follower in some of these opportunities. So we can find the sweet spot, we identify the sweet spot early, try to get it early and capture the position at a cheap cost.

We're trying to replicate the $300 an acre Eagle Fords and we did that in Niobrara. And we've done that in the Duvernay, the Montney and the Canol. And that's what we're doing. We're doing that in Columbia. We're doing that in other places around the world.

So that's a part of A, maybe small A, but we are spending a fair portion of our exploration dollars right now the $2.2 billion to $2.3 billion on that piece of the business. You do have to look at exploration differently today. You have to look at it through an unconventional lens and a conventional lens. And it has different implications due to portfolio.

Over here. We'll do Iain and next to order and then we'll catch--

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Iain Reid - ***Jefferies & Company, Inc. - Analyst***

Yes, hi it's Iain Reid from Jefferies. Can I ask a question about exploration? Is it possible to say what level of risk or maybe on risk reserves you're testing in your activities and exploration per say of the 2013 to '14 and maybe if you can try and break that up between the key areas. I'm thinking about Angola pre-salt and the Gulf of Mexico. And also maybe as part of that, identify which wells do you think are going to deliver the highest bang for buck either in terms of reserves proved up or NPV per well.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

So you want me to jinx our exploration program right out of the shoot Iain? Well I can't say what we're putting in terms of risk type the numbers on it. And I just go back to what we're excited about. We're looking around the deepwater provinces around the world. This business has moved a bit from resource constraints to resource abundance. We see that on the unconventional side. We see that developing in the deepwater side.

We're excited about our deepwater Gulf of Mexico program. We showed you what we're doing in Angola. Matt said he didn't talk about some of the others. The Poseidon in Browse, he talked about. But there's Bangladesh, we're early mover into the Bangle fan. We're taking a hard look at that. We've gone northern into the Barrents Sea in Norway.

So he talked about other kinds of areas, but certainly we're taking a very, very technical science lead approach to how we're doing it. And we're risking them appropriately. We're building a global portfolio of opportunities. We're thinking about unconventional and conventional and risking them differently. And I think watch the space, '13 and '14 are important years for us in this space. We've got to put some runs on the board. And that we've already started. We're already seeing some success.

Jason Gammel - ***Macquarie - Analyst***

Thanks. Jason Gammel with Macquarie, I just wanted to square some of the comments about the oil sand business and potentially reducing some equity in that business relative to comments about potentially bringing in the cost structure down by $20 a barrel and seeing better realizations.

When do you think you could actually realize the value that should be associated with those cost savings and margin increases? Is that something you think as a two or three-year time window or is that further down? What level of exposure would you like have in the oil sands? And are you talking about selling the un-producing assets or would this involve FCCL and Surmont?

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Well, we're looking across the whole oil sands portfolio. So we have a 16 billion barrel resource position and Al and Matt both described the quality of the position that we have. It is made up of three different yet distinct assets. It is our partnership in FCCL. It is our operation and our different partnership at Surmont. And then it's some undeveloped 100% acreage that we own called Thornbury, Clyden and Saleski.

Well, we're not going to develop that in 100%. So, we're looking at various options and choices we have to lighten up that position. I don't have a specific target in mind right now, but just telling you overtime in longer term, we'd like to bring that position down. We've got a great position and we're going to look at different structures that make sense.

With the dislocation in bitumen right now, we think that's short term. We don't see it impacting the market too much today in terms of A and B or in terms of potential suitors. Because the resource position is so large, so long over a long period of time, I think people are looking at that and saying those differentials will start to collapse over time.

But we're looking at various options around it and certainly it was complicated a little bit with the CNOOC acquisition of Nexen. So we have to be aware of what that in terms of developing our plans with how we're going to do it. So I can't get too specific with you because we're looking at lots of different options about how we might choose to lighten up our position there.

Paul.

Paul Cheng - ***Barclays Capital - Analyst***

Thank you, Ryan. Paul Cheng, Barclays. I have three sought questions. First cost inflation, where you see the biggest pressure right now and what's your expectation over the next several years, your unit cost inflation pressure? Second, based on your comments, it seems like M&A is not going to be a permanent part of your overall strategy or portfolio for the next maybe two or three years, I just wanted to confirm.

And last one, you're going to do a lot of things and that some could be labor intensive in the Lower 48. So from a human capability standpoint, where you stand, are you reaching close to you human capability limit with all the things that you're doing or that you actually have far more room? Thank you.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

All right. Thank you. So three question, make sure I get this right, Paul. The first one on cost inflation, I guess there are pockets around the world that are a little bit different. In the US Lower 48 over the last couple years, it was rigs and pressure pumping services. But as Al indicated, we saw a little bit of reduction in that and drop off coming out of the low gas prices of 2010 and 2011.

But I think generally, we see a couple percent of inflation across the business. There are hotspots, there is labor. Labor is a little bit tougher in Australia these days. So there are bits and pieces of it around. Certainly, the North American business is seeing a little bit more inflation just in some specific aspects of it. But I don't think over term we see a lot of change relative to a couple of percent.

Paul Cheng - ***Barclays Capital - Analyst***

(Inaudible - microphone inaccessible)

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

And I think that's how we long term plan it, yes. Yes, M&A, Paul, I'm not out there trying to find a big acquisition to go do for the Company. Again, we're focused on organic we grow on the Company. We got the portfolio to do it. We got the options to go do it. That's what we're focused on delivering. And I forgot your last.

Paul Cheng - ***Barclays Capital - Analyst***

Human capability.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Human capability, thank you. Yes. Certainly, all of us are in that position. I think Larry has a favorite saying that, if you can spell shale you can get a job now in the United States. So, that's certainly probably still the case. But we're doing our fair share. As we came out as an independent E&P company, we're pretty focused on being able to tell our folks that we're being competitive against the peer group that we see, and that peer group includes independents and integrated majors.

We've done well to reduce our attrition rates down and we're out in the campuses, we're experience hiring. We're hiring out of the campuses. So, we know the plans we have in front of us and we have a work force plan to deliver on our plan. So we haven't hit the constraint yet.

Now back over here. And then I'll come back over here.

Blake Fernandez - ***Howard Weil - Analyst***

Thanks, it's Blake Fernandez with Howard Weil. I had a question for you on the dividends. Obviously, you're in a period of increasing the production in margins in order to reach a cash flow breakeven to actually fund the dividend from ops. And I'm just curious, how comfortable are you with the CapEx at the $16 billion level remaining flat.

Historically, industry wide you would tend to think of some inflation there. And then secondly, is it fair to think any additional dividend increases would not come until you've actually reached that cash flow breakeven level? Thanks.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

So a good question on the CapEx. We think in terms of approximately $16 billion I think over the next couple of years, three years, it could be a little bit less than that, it could be a little bit more. It's primarily tied to the dispositions that we have announced when they close. That has some impact on where the capital is going to be, and then our efforts as I talked about, to rebalance the portfolio. So it could be a little bit higher, could be a little bit lower. But that's why we're showing approximately $16 billion over the course of this plan.

The dividend, again, its important part of our underpinning, you should expect modest increases over time. That's -- we think that's important. We think that's something we ought to be doing and that's what we're target of doing and it's built into our plans.

Over here.

Robert Kessler - ***Tudor, Pickering, Holt & Co. - Analyst***

Thanks, Ryan. Hi it's Robert Kessler, Tudor, Pickering. I wanted to ask about Alaska specifically and your decline mitigation investments more broadly. In Alaska, you referenced mitigating or your intent to mitigate the decline rate to 3% per year. Overtime, you use Kuparuk as an example, octolaterals. When I look at Kuparuk, the three year average decline rate's been 3% up through 2011. I'm sorry 5%, but it accelerated to 7.4% in 2012. And maintenance activity would appear to have been more significant last year.

So I ask for two reasons, or ask about that for two reasons. One is to understand Kuparuk specifically and why we're not seeing some results there up front. And more broadly to highlight or ask, is there a risk that higher down time, lower utilization may precede lower decline rates in your portfolio generally in this strategy.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Let me ask Matt. You want to take that one?

Matthew Fox - ***ConocoPhillips - EVP - Exploration & Production***

So the claim rate change in Kuparuk last year was really a very large maintenance program in Kuparuk. The underlying decline across the whole slope from Alpine, the satellites in Prudhoe and Kuparuk and is going to be mitigated to about 3% on average over the five years, maybe a little bit earlier but more early as you can see on the graph. You can scale about [off] and that's our expectation of the aggregate of the slope.

From the -- I think I said, when we add the Alpine west project on it comes about 2%. And if the fiscal regime changes to encourage additional investment, opportunities exist to reverse the decline in Alaska, opportunities from expanding our development programs and adding major projects. So we're hopeful that that will happen, because a lot of opportunity still exists in our Alaska business.

Robert Kessler *- Tudor, Pickering, Holt & Co. - Analyst*

And do you think that, again, along the lines of a lower utilization rate, while you work on the fields to mitigate the decline rate, longer term. Do you expect the field to come down as you tie in --?

Matthew Fox *- ConocoPhillips - EVP - Exploration & Production*

Apart from the plan maintenance activity which varies from year to year depending on what proper maintenance would actually do. No, I don't expect to see any significant degradation in direct operating efficiency in Alaska or for that matter, across the board.

Now, there is some additional down time in our European assets in particular this summer as we're preparing to tie in Ekofisk South, Eldfisk II and Jasmine. So we will have an unusually high level of down time in our European assets this year.

Ryan Lance *- ConocoPhillips - Chairman, CEO*

Back here (inaudible)

John Herrlin *- Societe Generale - Analyst*

Herrlin, Soc Gen, in the Lower 48 states over the last three years, your CapEx has gone from $1.8 billion to $5 billion plus. You've addressed how you're going to be integrated in your approach to field managements but these basins are all fairly competitive. So I'm curious as to what you're spending or activity capacity is in the Lower 48 states. Is the $5.3 billion we're seeing more or less static? I'm assuming a lot of it is on shore in terms of your spend, or could you actually ramp that up if you so desired?

Ryan Lance *- ConocoPhillips - Chairman, CEO*

No, our plan is, I said as we rebalance the portfolio, we get our production -- held by production and our intention is to ramp up the spend in the unconventionals. We've got the capacity, the capability to go do that. That's the advantage of a large position that we have in North America. We could move rigs around to where the programs are working and where they're not working so well. But our intention is, you should see us ramping up some of that spend over time.

John Herrlin *- Societe Generale - Analyst*

But how much higher? That's what I'm wondering.

Ryan Lance *- ConocoPhillips - Chairman, CEO*

Well I don't have the specific numbers in mind. I think as we again, we're trying to pace it with infrastructure that's coming and the opportunity sets there. And when we figure out ultimately what the down spacing, that's the most optimum for things like Bakken and Permian and the Eagle Ford, we don't know that quite yet. We're taking a more measured approach to make sure we don't over capitalize these plays. Some are over capitalizing. I can't prove it definitively with science but that's what we're intending to go do.

So before we get carried away, we're going to make sure we optimize the completions. We're going to make sure the infrastructure is there. And we're going to make sure we know how to -- this ultimate spacing we think is optimum to drill down to. And we don't quite know that yet in most of these unconventional that we're developing today.

John Herrlin *- Societe Generale - Analyst*

Okay, I have one for Matt. With the Niobrara, you didn't give any well specifics. Can you tell us what you -- what they were testing or what the EORs might be?

Matthew Fox *- ConocoPhillips - EVP - Exploration & Production*

I think said we drilled there four wells, and none of those have been on long term test. We've been drilling relatively short laterals. We've been testing different orientations of the laterals. So we don't really have anything that would be a representative number to put out there as what we ultimately expect to have from these wells. But the results are very encouraging. The yields in particular are very encouraging. Yes, so overtime that would become more apparent but there's just not beneficial to throw a number that wouldn't be representative.

Ryan Lance *- ConocoPhillips - Chairman, CEO*

One back here please.

Evan Calio *- Morgan Stanley - Analyst*

Thank you. Evan Calio of Morgan Stanley. Two questions, largely a follow up in nature. Number one, could you quantify an amount or what percentage of the five year $25 billion North American Lower 48 CapEx spend, it would be infrastructure related to introduce a significant infrastructure associated spending number there I'm sure.

And secondly, with regards to Alaska, there have been very recent proposals to roll back tax progressivity and I know Conoco's spending past four year into the Chuckchi. Payment is largely tapered since '06, and introduction to that higher tax. Any thoughts there on that tax and if it were to be made flat, you know do you see capital opportunities there greater than current? Thank you.

Ryan Lance *- ConocoPhillips - Chairman, CEO*

Yes. So you're first question on the $5 billion of Lower 48 spend. I think there's about $1.5 billion, $2 billion that is in the infrastructure that we're building. So we are making sure that we protect the net back to the leases. So if that means putting in facilities, pipelines and extra infrastructure to go do that. We'll make those investments to protect our net back and our prices and optimize the developments. Now we are looking to get on third party infrastructure as well. But that gives you a rough idea of maybe of what we're trying to do.

In Alaska, we certainly, we've told the governor and Matt described it today as well. We'd be willing to make additional investments in Alaska. It would be competitive in our portfolio if there was less progressivity built in that currently exists in the fiscal regime that Alaska has. We're hopeful, they're going through session right now. There's been multiple proposals that have been floated around. Some a little bit better than others. But the message we have is that we do see additional opportunity in all three of the major fields. Prudhoe Bay, Kuparuk and Westover at Alpine, if there was a more competitive fiscal regime, we'd be willing to invest more money up there than obviously would then create more opportunities.

Over in the corner, you get it next Faisel again.

Roger Read *- Wells Fargo - Analyst*

Roger Read, Wells Fargo. Just a question coming back to the dividend again versus the CapEx question and balance sheet, dept levels and the business it's inherently volatile price wise and everything. If the dividend is important and growth is important, why not take some of the free cash here from the asset sales and improve the balance sheet such that come '14 or '15 if we were to hit a lower oil price period, for a short time or even a medium time, that you would be able to pursue the growth opportunities out to '17 and not have to make a step back. In other words, what is the full thinking on the cycle balance sheet strength which, while it looks good today, we'd look very different in, $50, $60, $70 oil price environment?

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Jeff, you want to take that one?

Jeffrey Sheets - ***ConocoPhillips - EVP - Finance, CFO***

Again, look at where we are today, $4 billion in cash at the end of the year, $9.5 billion of asset sales proceeds coming in. We're going to be building cash. Now, obviously we're spending capital and paying the dividend at a rate excess of cash flow, so some of the asset sales proceeds are going to be used to fund that, but probably all in, we close all these things, we end up with more cash on the balance sheet. So we got a lot of flexibility to fund on in through '14 and '15 and then prices stay where they are when this gap closes.

So if we look at our plan today, we don't really use the balance sheet to make that happen. But the balance sheet is there. If prices are different than what we think they're going to be then, and we need to use a balance sheet, there's space there to do that. So, really it's a belts and suspenders, we got cash from operations, we got asset sales proceeds, we got cash on the balance sheet already and we got dept capacity.

So there really shouldn't any doubt that through those series of price environments that we can fund that capital and fund the dividend. So whether the balance sheet, whether it's there and has cash or whether it's there as a lower debt balance, we think it still represents balance sheet strength.

Faisel Khan - ***Citigroup - Analyst***

Thanks. Faisel Khan from Citigroup going back to APLNG, I just wanted to clarify some of the comments you made. The project is about 5% to 7% over budget. And then I heard a number, 20% in US dollar basis. Can you just clarify exactly currency to currency what we're using here and what the numbers are for the budget for APLNG and where we are with that?

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Matt's my engineer. He's got the decimals in his brain so.

Matthew Fox - ***ConocoPhillips - EVP - Exploration & Production***

Yes. So say about a 7% increase over the on an Aussie dollar basis. We spend for about 30% of the capital. That 30% was spent with an Aussie-US exchange rate of about [$1.04, $1.05] in favor of the Aussie dollar. If you look at the forward curve, the forward curve has the US dollar strengthening and that is swapping over to be a stronger US dollar, more comparative to the US dollar.

We don't know exactly how that's going to work out. So our expectation, the range that I gave you of 20% to 25%, that's based on the assumption of the average over the life of the project as parity to the average over the life of the project is more like $1.04, $1.05. So that was a basis. Was that your question Faisel?

Faisel Khan - ***Citigroup - Analyst***

Yes. So you've just taken the project, the 20% of the budget (inaudible) US dollar in terms of (inaudible) currency?

Matthew Fox - ***ConocoPhillips - EVP - Exploration & Production***

That's right. So, the reason I draw the distinction here is that what I'm most concerned about is the project being executed well. I can't do anything about FX. But what I can do things about is making sure the project's been executed well. So the reason that we took -- that we did this bottom's up review was to give us comfort that we are executing this project well.

Other projects in Australia have seen serious cost overruns, much more serious cost overruns than we're seeing in APLNG. The bottom line in APLNG is the project's running well. You ever seen cost pressures, I mean, the wages and the changes in regulations and -- but the project is running well. And on an as spent dollar basis, a 7% increase is disappointing but it's not all that bad. Now when you translate that to US dollar basis the FX is going to be what FX is going to be.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Over here.

Scott Hanold - ***RBC Capital Market - Analyst***

Yes, it's Scott Hanold from RBC Capital Markets. A couple questions, the first is in the Gulf of Mexico, you've got that patch of 100% owned -- I guess 180,000 acres in Green Canyon. What is your view in terms of what you'd like to be in terms of working interest as you go and look in those prospects and what could the deal terms look like for Conoco?

And the second question's on the Eagle Ford Shale in your 1.8 billion barrels of resource potential. What type of recovery does that assume? Is there any improvement from where we are right now and where ultimately does that go to? And is it -- is there some things you guys are working on right now that you can talk to that gets you there?

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

Yes. So on the Gulf of Mexico, we typically won't do things at 100% but we like to be the operator of the stuff that we have. You're able to get leverage on good prospects on the Gulf of Mexico. So we're always going to be out there looking, probably not developing things or exploring for things at 100%. We'd like to stay the operator which means we'll keep a majority interest, but we'll look for leverage to reduce the risk and bring partners into those kinds of opportunities.

On the Eagle Ford, Matt can correct me if I'm wrong, but we're planning and drilling today on 160s and we're thinking probably down the 80 acre spacings or probably reasonable to go do. We have some questions below that, so what we built into our plans is efforts to move to an 80 acre spacing.

Go ahead Matt, you wanted something to add?

Matthew Fox - ***ConocoPhillips - EVP - Exploration & Production***

Yes, the resource space is based on the assumption that we -- it's not based on an assumption that we improve the recovery further. It's based on our current type curves. Our current assessment about what we should expect to 80 acre spacing. Then as Al said, we're looking at technology improvements and our expectation would be about the growth of resource space, but that's not what's reflected in the numbers that we showed today.

Scott Hanold - ***RBC Capital Market - Analyst***

Where does the actual recovery percentage here, assuming for the reservoir itself?

Matthew Fox - ***ConocoPhillips - EVP - Exploration & Production***

This goes back to the understanding of the underlying physics of these unconventional reservoirs. It's not easy to understand how much hydro carbons are out there in the first place, how much of the kerogen has been converted to oil or gas. It's not easy to fully understand the porosity. People throw out recovery factors based on what they know. Typically for these place are in the high single digits, in their oil rich place.

Bottom line is if people are honest, they don't really know what the recovery factors are, because they're not 100% sure where the oil and plays really is.

Ryan Lance - ***ConocoPhillips - Chairman, CEO***

May we take one more? Maybe not, or one over here, okay, last question please.

Boris Raykin *- Granite Associates - Analyst*

Boris Raykin, Granite Associates. I had a question about your strategy in the Permian basin and the gifts on giving, and especially in the conventional part versus the unconventional. So, what kind of returns are you seeing there, what your strategy is for developing that how much running room you have there?

Ryan Lance *- ConocoPhillips - Chairman, CEO*

Well as Matt described, we've got a huge 1.1 million acre held by a production position which gives us a lot of luxury. We can go fast or slow, make sure we're doing it right. We're pretty agnostic whether it's unconventional or conventional right now. We're just really trying to drill the highest return stuff. We're not in a hurry. We can pace it with infrastructure. So even though this is a 100-year-old basin, it still needs some infrastructure to be able to take on this growth. It needs gas plants. It needs more evacuation capacity, going out of the basin.

We're not in a hurry to drill because we've got it held by production. So, we were pretty agnostic about whether it's conventional or unconventional, just trying to rank it and do the most profitable things first.

Well let me thank you again for your interest and your participation today. I think for those that can stick around, we have some lunch on the 7th floor. I would just reiterate probably the one thing, which is this is what we're about. This is our value proposition. We're going to run the business well. Our dividend is differential. We're going to grow it. It's not just growth for growth's sake, its high margin growth, and we really do have a laser like focus around improving the returns in this business. So, that's what ConocoPhillips is about, and I thank you for your attention.

Editor

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

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